



2019 INTEGRATED RESOURCE PLAN

And Application for Certification of Capacity from Plant Scherer Unit 3 and Plant Goat Rock Units 9-12 and Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Euston Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2
Docket No. 42310



GEORGIA POWER COMPANY'S 2019 INTEGRATED RESOURCE PLAN DOCKET NO. 42310

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2019 INTEGRATED RESOURCE PLAN

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CHAPTER 1. EXECUTIVE SUMMARY

This 2019 Integrated Resource Plan (“2019 IRP” or “IRP”) is filed in compliance with O.C.G.A. § 46-3A-2, which requires the filing of such a plan every three years. Specifically, this 2019 IRP “demonstrates the economic, environmental, and other benefits to the state and to customers of the utility, associated with” improvements in energy efficiency, alternative sources of energy, cogeneration and hydroelectric (“hydro”) facilities, and demand-side options (“DSOs”) all as required by O.C.G.A. § 46-3A-2(b)(3).

As shown in this 2019 IRP, Georgia Power Company (“Georgia Power” or the “Company”) continues to navigate the evolving energy landscape, taking proactive steps to capitalize on current market conditions while also allowing the Company the ability to respond to several possible future conditions, for the benefit of customers. While working closely with the Georgia Public Service Commission (“Commission”), the Company’s experience shows that system planning that maintains a diverse generation fleet, robust transmission system, and a continued focus on energy efficiency has produced customer rates that remain well below the national average while customer satisfaction remains at the top of the industry.

The 2019 IRP was developed with this experience in mind and using the Company’s comprehensive planning process, which results in a plan through which the Company will continue to provide customers with reliable and affordable electric service from a diverse portfolio of demand-side and supply-side resources. This portfolio – comprised of demand response, energy efficiency, nuclear, natural gas, oil, coal, hydro, solar, wind, landfill gas, and biomass generation – provides significant benefit to customers and maximizes value for customers in a wide variety of future economic and regulatory scenarios.

Notably, this IRP reflects the ongoing evolution of the Company’s planning strategy through the procurement of energy from an additional 1,000 MW of renewable resources, continued implementation of demand-side programs, retirement of aging and economically challenged plants, compliance with environmental requirements, and deployment of battery energy storage technologies. By implementing each of these actions, continuing the construction and testing of Plant Vogtle Units 3-4, and investing in the long-term future of hydro operations, the Company is taking steps to ensure that its system will remain resilient and adapt to the energy needs of its customers for the foreseeable future. This IRP centers on preserving reliability through the



implementation of seasonal planning, issuance of capacity-based requests for proposals (“RFPs”), and strategically-focused reliability investments.

1.1. RELIABILITY AND SEASONAL PLANNING

In keeping with common utility practice, the Company demonstrates through its IRP process that it maintains a sufficient amount of demand- and supply-side resources to serve the needs of its customers. Given the uncertain nature of forecasts and of future conditions, the Company uses the IRP process to periodically re-evaluate its resource needs and to respond as necessary to ensure that its system continues to provide safe, reliable, and affordable energy to its customers.

Historically, the Company’s capacity planning decisions have been driven by a combination of summer peak loads and a corresponding summer-focused Target Reserve Margin. These planning techniques have proven to be successful in supporting reliability while cost-effectively meeting the needs of customers. However, recent operational experiences and forecasted conditions reflect a significant shift in reliability risk from the summer season to the winter season, thus requiring the Company to adapt its historically summer-based capacity planning approach to specifically address seasonal reliability needs. Due to continued increases in winter reliability risks, the Company is adopting seasonal planning to better address the winter reliability issues previously identified in the 2016 IRP. Seasonal planning provides greater visibility into both summer and winter capacity needs rather than limiting reliability decisions to a single season.

In support of this recommendation, Technical Appendix Volume 1 contains a detailed reliability analysis reflected in the 2018 Reserve Margin Study (“Reserve Margin Study”) that addresses Target Reserve Margins for the Southern Company System (“System”). Based upon the Reserve Margin Study, the Company intends to utilize seasonal Target Reserve Margins for all future planning purposes. For long-term planning starting in 2022 and beyond, the Company’s plan maintains a Target Reserve Margin of 16.25% for summer periods (“Summer Target Reserve Margin”), which is the Target Reserve Margin approved in the 2016 IRP. For winter periods, the Company is adopting a long-term Target Reserve Margin of 26% (“Winter Target Reserve Margin”). Despite implementation of the seasonal Target Reserve Margins, Georgia Power’s next capacity need occurs in the summer rather than in the winter, indicating that the timing of the Company’s next capacity-based decision will continue to be driven by summer



needs. Future capacity planning decisions, however, could be driven by winter needs, especially if winter reliability risks are not adequately addressed.

Consistent with past practice, the Company also evaluated the short term (2019-2021) Target Reserve Margin and plans to adopt 15.75% for summer and 25.5% for winter. No resource decisions have been altered in this IRP based on the Company's recommended Winter Target Reserve Margin. However, the Company includes sensitivities to demonstrate that while the change is minimal for Georgia Power in this IRP, adoption is necessary to enable the Company to act upon winter-based reliability concerns. A detailed review of these requirements can be found in CHAPTER 5. as well as Technical Appendix Volume 1.

1.2. LOAD AND ENERGY FORECASTS

Twenty-year forecasts of energy sales and peak demand were developed to meet Georgia Power's planning needs. Although the difference between the weather-normal summer and weather-normal winter peaks is narrowing, Georgia Power remains a summer-peaking utility. The Budget 2019 Load and Energy Forecasts ("Budget 2019") include the retail classes of residential, commercial, industrial, Metropolitan Atlanta Rapid Transit Authority ("MARTA"), and governmental lighting. The baseline forecast was started in the spring of 2018 and completed in the fall of 2018. An overview of the process, assumptions, and modeling of the energy and load forecasts is provided in CHAPTER 6. and discussed in greater detail in the Budget 2019 Load and Energy Forecasts, found in Technical Appendix Volume 1.

1.3. DEMAND-SIDE STRATEGY

The Company's current demand-side management ("DSM") portfolio consists of demand response programs, energy efficiency programs, pricing tariffs, and other activities. The Company projects that by 2022 this portfolio will represent approximately 1,600 MW, or approximately 10% of the Company's current peak demand.

In accordance with the 2016 IRP Order, the Company continues to work closely with the DSM Working Group ("DSMWG"), using the DSM Program Planning Approach for DSM program development. The Company prepared a Technical Reference Manual, completed and filed an energy efficiency potential study, and conducted a comprehensive analysis of potential DSM programs with the assistance and input of the DSMWG.



The Company seeks approval of its recommended DSM action plan including a certificate for three new DSM programs, amended certificates for three certified DSM programs, decertification of two DSM programs, and updated program economics for the remaining five previously-certified DSM programs in the Company's 2016 DSM Application. The Company also intends to continue the Power Credit residential program, which was certified in Docket No. 6315.

In preparing its Proposed Case, the Company acknowledges that avoided cost savings are lower than those projected in the 2016 IRP, which has a negative impact on the economics of the Company's current and proposed DSM programs relative to the economics projected in the 2016 IRP. As discussed in CHAPTER 7., Total Resource Cost ("TRC") Test results declined and Ratepayer Impact Measure ("RIM") Test results worsened, raising concerns for the Company in its effort to balance the economic benefits these programs provide to participating customers with the rate impacts to all customers within a given class. Nevertheless, the Company supports the continuation of all but two of the energy efficiency programs included in the 2016 DSM Certification filing and seeks to certify a residential demand response program, a residential Income-Qualified program, and a Commercial Behavioral program. The Company plans to continue to monitor program costs and economics through 2021 and will be prepared to modify programs if the significant upward pressure on rates continues. Summary information for two alternative DSM sensitivity cases is also included in this filing. One alternative sensitivity case, the "Advocacy Case," presents a potential set of DSM programs designed based on the recommendations from members of the DSMWG. The other alternative sensitivity case represents the "Aggressive Case" that is required in the DSM Program Planning Approach.

1.4. SUPPLY-SIDE STRATEGY

Georgia Power's proposed supply-side plan, further expounded upon in this chapter, will provide cost-effective and reliable sources of capacity and energy to meet Georgia Power's customers' needs now and into the future. The supply-side strategy includes both certification requests for new capacity as well as decertification requests. The planned and committed resources in this IRP provide for adequate reserves until 2028 at which point the Company is currently projected to have a capacity need. However, as discussed further in this chapter and in CHAPTER 10., the Company may encounter a capacity need prior to 2028 due to potential unit retirements. To satisfy capacity needs and maintain reliable electric service, the Company plans to issue two capacity-based RFPs.



As further addressed in CHAPTER 9., Georgia Power conducted a review of its hydro fleet and determined that essential components of several facilities are at or near the end of their useful lives, requiring additional investment to continue their operation. These investments will improve the overall efficiency, integrity, and safety of the hydro fleet while preserving these valuable carbon-free resources for the long-term benefit of customers. For example, the new investments for Plant Goat Rock will improve reliability, correct for water flow imbalances along the Chattahoochee River, and result in capacity increases as requested in the Company's certification application.

The Company also proposes to invest in energy storage technologies that can be deployed both independently and in tandem with solar resources, so Georgia Power can continue to improve its understanding and expertise related to energy storage technologies for the benefit of customers. The deployment of these energy storage projects is further discussed in CHAPTER 10..

1.5. RENEWABLE RESOURCES

Georgia is recognized as a national leader in the development of cost-effective renewable resources without a renewable portfolio standard ("RPS") or mandate. Through the leadership of the Commission and collaboration with stakeholders, Georgia Power expects to have approximately 3.1 gigawatts ("GW") of renewable resource capacity online by the end of 2021 through currently approved projects. This portfolio of renewable resources includes approximately 340 MW of biomass and landfill gas, 250 MW of wind, and more than 2.5 GW of solar resources, which currently represents one of the largest voluntary solar portfolios in the nation for an investor-owned utility.¹

The 2019 IRP continues the steady approach of adding renewable resources projected to create long term savings for customers by procuring an additional 1,000 MW of renewable resources. To maximize benefits for customers, these resources will be procured through a competitive bidding process and evaluated utilizing the Renewable Cost Benefit Framework ("RCB Framework") approved by the Commission following the 2016 IRP. These procurement programs maintain the customer-focused strategy of growing renewables to deliver the most

¹ Georgia Power purchases only the null energy output from some renewable generating facilities that have contracted to sell energy from their facilities to Georgia Power. The ownership of the associated renewable energy credits ("RECs") is specified in each respective power purchase agreement ("PPA") and the party that owns the RECs retains the right to use the RECs. Georgia Power does not report emission reductions from the null energy purchased through PPAs that do not bundle the RECs for sale to Georgia Power.



benefits for all customers at the lowest cost. These programs will offer renewable options that meet the needs of customers and improve the competitiveness of Georgia's business environment. The new Customer Renewable Supply Procurement ("CRSP") program, modeled after the successful commercial and industrial ("C&I") Renewable Energy Development Initiative ("REDI") program, will procure 950 MW of utility-scale renewable resources available for subscription to both new and existing customers. Additionally, the Company plans to procure up to 50 MW of renewable distributed generation ("DG") resources to continue to support the development of this market segment. For both the utility-scale and DG procurements, the Company proposes to continue sharing the projected long-term benefits realized from the Power Purchase Agreements ("PPAs").

Lastly, the Company remains committed to supporting customers interested in renewable energy through education, analysis, and the delivery of customer-focused renewable programs, including a proposed enhancement to Georgia Power's Simple Solar program. The Company plans to add an additional discounted pricing tier for Simple Solar Large Volume participants, allowing greater pricing flexibility for large energy users. Customer interest in solar continues to increase, and Georgia Power is dedicated to providing a robust response to those needs.

1.6. ENVIRONMENTAL STRATEGY

Georgia Power has developed a comprehensive environmental compliance strategy that identifies the Company's plans to comply with all applicable state and federal environmental laws and regulations, including, without limitation, the Clean Air Act, Clean Water Act, and the Resource Conservation and Recovery Act. The strategy enables Georgia Power to comprehensively manage environmental compliance and effectively address specific compliance requirements through the implementation of cost-effective and commercially available environmental control applications.

As described in CHAPTER 10., through successful implementation of previous strategies approved by the Commission, the Company has achieved dramatic emission reductions and implemented effective environmental controls through making the most economical decisions in the best interest of customers. The Company's current strategy incorporates new technology installations, compliance actions, and associated costs to comply with recent land and water regulations, such as the Coal Combustion Residuals ("CCR") and Effluent Limitations Guidelines ("ELG") rules. The strategy and the associated costs are discussed in detail in the



Environmental Compliance Strategy (“ECS”) in Technical Appendix Volume 2 and the Environmental Compliance Cost Recovery (“ECCR”) and CCR Asset Retirement Obligation (“ARO”) tables in the Selected Supporting Information section of Technical Appendix Volume 1.

1.7. UNIT RETIREMENTS

The Company has performed an in-depth economic analysis of certain fossil-fuel-fired generating units to determine which units will continue to provide economic benefits to customers. The results of this analysis show that sustained low gas prices combined with reduced energy demand growth continue to place economic pressure on the Company’s remaining coal-fired generating units. Consequently, the Company recommends retirement of Plant McIntosh Unit 1 and Plant Hammond Units 1-4.

The Company plans to continue operation of the remaining coal fleet based on the benefits these units provide to customers. For Plant Bowen Units 1-2, the Company acknowledges the economic challenges associated with continued operation of these units in certain scenarios but recognizes that immediate retirement of these units would be premature and expose customers to significant reliability risk associated with generation capacity shortfall. Moreover, the absence of these units requires construction of significant transmission system upgrades to support reliable operations. Therefore, the Company plans to defer major resource decisions for these units to avoid any irreversible decisions that may be contrary to the long-term interests of customers. To provide decision-making flexibility, the Company plans to take the appropriate steps to ensure future reliability, which includes making the appropriate transmission upgrades and issuing two capacity-based RFPs. As discussed in CHAPTER 10., the first RFP will seek resources that can provide capacity beginning in 2022-2023 (“2022-2023 RFP”) due to the economic challenges associated with Plant Bowen Units 1-2, while the second RFP will seek resources that can provide capacity beginning in 2026-2028 (“2026-2028 RFP”) ahead of the Company’s currently forecasted capacity need.

The Company also intends to retire three small hydro plants – Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2. These plants went into service in 1929, 1908, and 1918, respectively, and represent a total 0.4 MW of retail capacity. Due to the size, age, and location of these facilities, the Company does not believe material impacts to the local communities or reliability will result from the proposed retirements. Additionally, as discussed in CHAPTER 9., natural resource agencies support retirement of these units.



1.8. WHOLESALE GENERATION

Approximately 25 MW of Plant Scherer Unit 3 capacity will be available to serve retail customers after December 31, 2019, following the expiration of an existing wholesale PPA. Consistent with the Commission's July 30, 2008 Order in Docket No. 26550, Georgia Power proposes to offer these 25 MW of capacity to retail jurisdiction beginning January 1, 2020. Additional information on the wholesale-to-retail transaction can be found in CHAPTER 11..

1.9. TRANSMISSION

The 2019 IRP includes the Company's updated ten-year transmission plan, which identifies the transmission improvements needed to maintain a strong and reliable transmission system. The development of this plan is conducted in accordance with Southern Company and Georgia Integrated Transmission System ("ITS") transmission planning guidelines and with North American Electric Reliability Council ("NERC") planning standards. Georgia Power, Georgia Transmission Corporation ("GTC"), Municipal Electric Authority of Georgia ("MEAG Power"), and Dalton Utilities (collectively, the "ITS Participants") developed this ten-year plan together in support of the Georgia ITS. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia ITS as required by the amended rules adopted by the Commission in Docket No. 25981. Additional transmission information is also provided as required by Docket No. 31081.

1.10. EMERGING RESILIENCE NEEDS

This IRP includes a new chapter addressing the Company's commitment to maintain a robust and resilient electric system as the generation fleet evolves towards a larger share of resources that either have no on-site fuel storage or are intermittent. CHAPTER 13. discusses resilience with respect to the power delivery system, the bulk power system, and generation assets. The Company is **not** proposing specific resilience enhancements in this IRP, but rather seeks to inform the Commission of the Company's forward-looking focus on resilience planning as a means of ensuring that it continues to meet Georgia's electric service needs during high-impact disruptive events.



1.11. CONCLUSION

In summary, the 2019 IRP sets forth a comprehensive plan that complies with O.C.G.A. § 46-3A-2 and this Commission's rules, and through which the Company shows its plans to continue to provide customers with clean, safe, reliable, and affordable electric service to meet the energy demands of its customers and the state of Georgia as its population and economy continue to grow. As such, the Company seeks approval of the 2019 IRP and associated Action Plan contained in CHAPTER 14., including the following:

1. Adoption of seasonal planning to provide greater visibility into both summer and winter capacity needs;
2. The Reserve Margin Study and its associated outputs, including continued use of a 16.25% Summer Target Reserve Margin, the addition of a 26% Winter Target Reserve Margin, and the associated short-term Target Reserve Margins for each season;
3. A certificate of public convenience and necessity for three new DSM programs, decertification of two DSM programs, amended certificates for three DSM programs, approval of the Income-Qualified Tariff-Based pilot program, and approval of updated program economics for all other previously certified DSM programs as further specified in the 2019 DSM Application, Docket No. 42311;
4. The revised calculation of the additional sum collected through DSM programs certified in the 2019 DSM Certification Application, Docket No. 42311;
5. Certification of approximately 18 MW of increased hydro capacity for Plant Goat Rock Units 9-12;
6. Procurement of an additional 950 MW of utility-scale renewable resources through the new CRSP program, utilizing a market-based approach;
7. Procurement of an additional 50 MW of DG renewable resources utilizing a market-based approach;
8. The levelized additional sum in the amount of 10% of the net present value of the projected benefits from the PPAs procured through the CRSP and DG programs;



9. The capital and operation and maintenance (“O&M”) costs the Company will incur for a portfolio of up to 50 MW of energy storage projects (but not yet the recovery), as set out in the Selected Supporting Information section of Technical Appendix Volume 1;
10. Revisions to the Simple Solar Tariff Large Volume Purchase Option pricing;
11. The capital, O&M, and CCR ARO costs (but not yet the recovery) and associated measures taken to comply with government-imposed environmental mandates, as set out in the ECS in Technical Appendix Volume 2 and the ECCR and CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 1;
12. Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2, effective as of the final order in this proceeding;
13. Initiation of a 2022-2023 capacity-based RFP and a 2026-2028 capacity-based RFP;
14. Reclassification of the remaining net book value of Plant Hammond Units 1-4 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective units' remaining useful lives as approved in Docket No. 36989;
15. Reclassification of the remaining net book value of Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a 3-year period in the Company's next base rate case;
16. Reclassification of any unusable material and supplies inventory balance remaining at the unit retirement dates to a regulatory asset for recovery over a period to be determined by the Commission in the Company's next base rate case, consistent with treatment of such balance in the 2016 IRP Order; and
17. Certification of 25 MW of wholesale capacity from Plant Scherer Unit 3 to be placed in retail rate base effective January 1, 2020.



CHAPTER 2. COMPANY OVERVIEW

Georgia Power, a wholly owned subsidiary of Southern Company, is an investor-owned electric utility that serves approximately 2.6 million retail customers in all but four of Georgia's 159 counties. Georgia Power electric service is available in 57,000 of the state's 59,000 square miles.

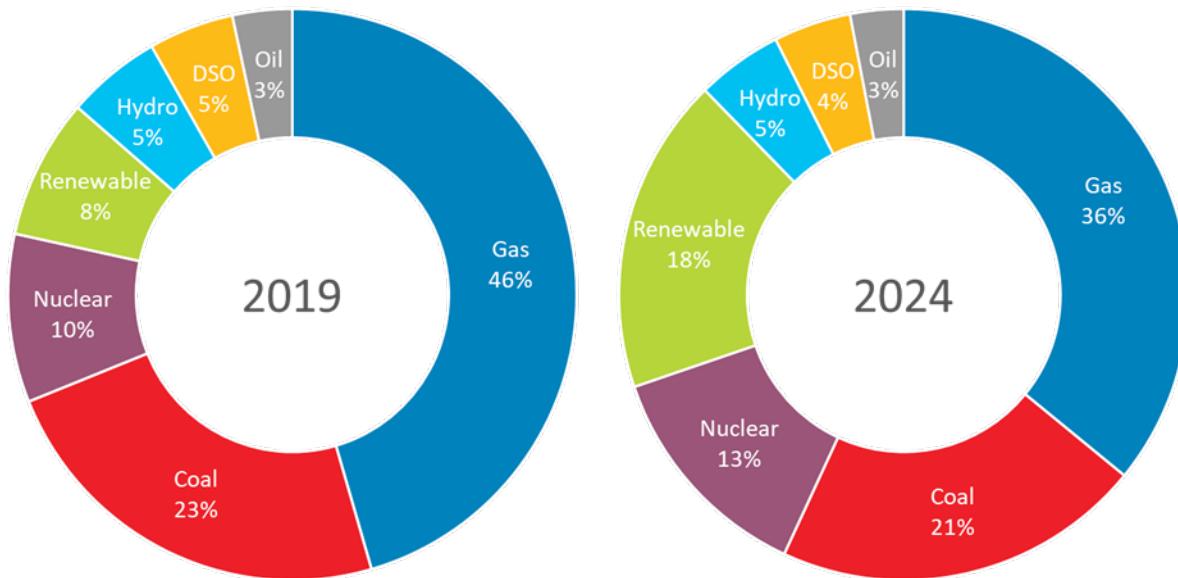
Southern Company is the parent of Georgia Power, Alabama Power Company ("Alabama Power"), Mississippi Power Company ("Mississippi Power"), Southern Power Company ("Southern Power"), and Southern Company Gas (formerly AGL Resources Inc.). On January 1, 2019, Southern Company completed the sale of Gulf Power Company ("Gulf Power") and other Florida assets to NextEra Energy, Inc. Gulf Power will remain part of the Pool² for a transition period and be treated similarly to the 12 months prior to closing. The "Transition Period" is defined as five years from the date the transaction closes with the possibility of an extension for two additional years. Although Southern Company and NextEra Energy agreed a five- to seven-year Transition Period will likely be needed, Gulf Power has the right to withdraw from the Pool at any time with 180 days' notice. The Company's analysis in this IRP assumes Gulf Power's continued participation in the Pool. Except where otherwise noted, Alabama Power, Georgia Power, Mississippi Power, and Gulf Power (collectively, the "Retail OpCos") as well as Southern Power are considered the electric "Operating Companies" for this 2019 IRP. The Retail OpCos will continue to be members of the Southeastern Electric Reliability Council ("SERC"), a group of electric utilities (and other electric-related utilities) coordinating operations and other measures to maintain a high level of reliability for the electrical system in the Southeastern United States ("US").

As of December 31, 2018, Georgia Power has ownership in 135 retail-serving generating units, including 5 combined cycle ("CC"), 16 fossil steam, 4 nuclear, 8 renewable, 71 hydro, and 31 combustion turbine ("CT") or diesel engine units, three of which at least have seasonal usage restrictions. Georgia Power meets retail customers' energy requirements and peak demands through a diverse portfolio of Company-owned resources, PPAs, and dispatchable DSOs. Of the energy generated to meet retail customers' needs in 2018, 45% was from natural gas, 25% from coal, 22% from nuclear, 3% from renewables, 2% from hydro, 2% from null energy, and less than 1% from oil-fired resources. Shown in Figure 1 are the Company's projected summer 2019

² Operating Companies operate their respective electric generating facilities and conduct their system operations (generally referred to as the "Pool") pursuant to and in accordance with the provisions of an interchange contract among themselves.



and summer 2024 capacity mixes, which account for the most recent unit capacity ratings and reflect approval of the certification and decertification requests expressed in this filing. Unit-specific capacity information can be found in the Resource Ledger contained in Technical Appendix Volume 2.



Note: These capacity mixes reflect demonstrated retail capacity for traditional resources, nameplate capacity for retail-serving renewable resources, and program capacity for dispatchable DSOs. A portion of the projected renewable generation capacity includes capacity where the renewable generator retains the related RECs.

Figure 1: Georgia Power's Projected Summer 2019 and Summer 2024 Capacity Mixes

CHAPTER 3. EXECUTION OF THE 2016 IRP ORDER

The Company's 2016 IRP was approved with modifications as specified in the Commission's final order dated August 2, 2016 (the "2016 IRP Order"). The approved 2016 IRP demonstrated "the economic, environmental, and other benefits to the state and to customers of the utility associated with" improvements in energy efficiency, alternative sources of energy, cogeneration and hydro facilities, and demand-side options all as required by O.C.G.A. § 46-3A-2(b)(3) and the Commission's rules.

Consistent with the 2016 IRP as approved, the Company took the following major actions:

1. Retired Plant Mitchell Units 3, 4A, and 4B; retired Plant Kraft Unit 1 CT; and completed the sale of the Company's ownership in the Intercession City CT to Duke Energy Florida;
2. Commenced site investigation and combined license ("COL") work at a site in Stewart County, Georgia, to preserve the option for new nuclear generation, and then subsequently suspended investigation and COL work in March 2017 when more current expansion plans indicated that suspending activities was unlikely to delay the ability to deploy new nuclear when needed by customers (see ATTACHMENT FFFFFFFFFFFFFF. for additional information);
3. Raised the System Target Reserve Margin to 16.25% and notified the Commission on November 4, 2016 that all of the Retail OpCos had formally approved utilization of a 16.25% long-term Target Reserve Margin;
4. Commenced execution of the necessary and approved environmental strategy to comply with government-imposed environmental mandates including completion of air-related controls for MATS compliance and initiation of construction and installation of equipment necessary for dry ash conversions, wastewater treatment, and preparation for ash pond closures at the Company's coal-fired plants in order to comply with federal and state rules and permits including the Clean Water Act and the Resource Conservation and Recovery Act;
5. Placed annual limits on all capital expenditures of \$1 million for Plant McIntosh Unit 1 and \$5 million for Plant Hammond Units 1-4 effective as of the date of the 2016 IRP Order;



6. Collaborated with Commission Staff to develop a Joint Recommendation for the continued implementation of the RCB Framework, which was approved by the Commission on December 22, 2016, with subsequent Commission approval in June of 2017 to apply the RCB Framework to Behind-the-Meter solar technologies, including, but not limited to, use in determining the Renewable and Nonrenewable Resources (“RNR”) Schedule;
7. Applied the RCB Framework in the evaluation of renewable self-builds, renewable RFPs, and Solar Avoided Costs projections;
8. Completed the first REDI RFP for 525 MW and procured 510 MW of utility-scale solar resources, with the resulting PPAs certified by the Commission in January 2018;
9. Issued the second utility-scale REDI RFP in December 2018 to procure the remaining 540 MW of utility-scale solar resources;
10. Designed and implemented the C&I REDI Program including the procurement of 177.5 MW of utility-scale solar resources to supply the four contracted C&I customers, with the resulting PPAs certified by the Commission in April 2018;
11. Issued the REDI Customer-Sited DG Program in November 2017 to procure approximately 47.9 MW of distributed solar resources;
12. Issued the REDI DG RFP in July 2018 to procure approximately 113.7 MW of distributed solar resources (including approximately 13.7 MW of roll-over capacity from prior programs);
13. Received approval and began developing nine self-build projects totaling approximately 200 MW, including projects at military bases and universities, projects to supply the Community Solar program, and the Right-of-Way Solar project with “The Ray”;
14. Commenced development of up to 10 MW of solar demonstration projects that will be located at closed ash ponds at Plant McDonough and Plant Hammond, with preliminary plans included as part of the ash pond closure permits, which are currently under review;



15. Deployed the High Wind demonstration project by purchasing, siting, and installing wind measurement instrumentation (Light Detection and Ranging, or “LiDAR”) to monitor high elevation wind data for two years at multiple locations;
16. Designed and implemented the Simple Solar program to replace the Company’s previous Green Energy program, which opened for both residential and commercial customer participation in January 2017;
17. Designed and implemented the Community Solar program, which opened for residential customer participation in January 2018;
18. Reported to the Commission concerning progress on the dismantlement and remediation of the Plant Kraft generating plant site and provided the Commission with appraisal information pertaining to the Plant Kraft land donation to the Georgia Ports Authority;
19. Collaborated with Commission Staff to address retirement study and other modeling approaches;
20. Completed and provided to Commission Staff a Technical Reference Manual in December 2017 for use with the Company’s DSM programs;
21. Filed the Achievable Energy Efficiency Potential Assessment in January 2018 in accordance with the DSM Program Planning Approach;
22. Filed complete Process and Impact Evaluation result reports in August 2018 for the energy efficiency programs certified in the 2016 DSM certification proceeding; and
23. Complied with the DSM Program Planning Approach to develop the Company’s 2019 IRP DSM plan.



CHAPTER 4. INTEGRATED RESOURCE PLANNING OVERVIEW

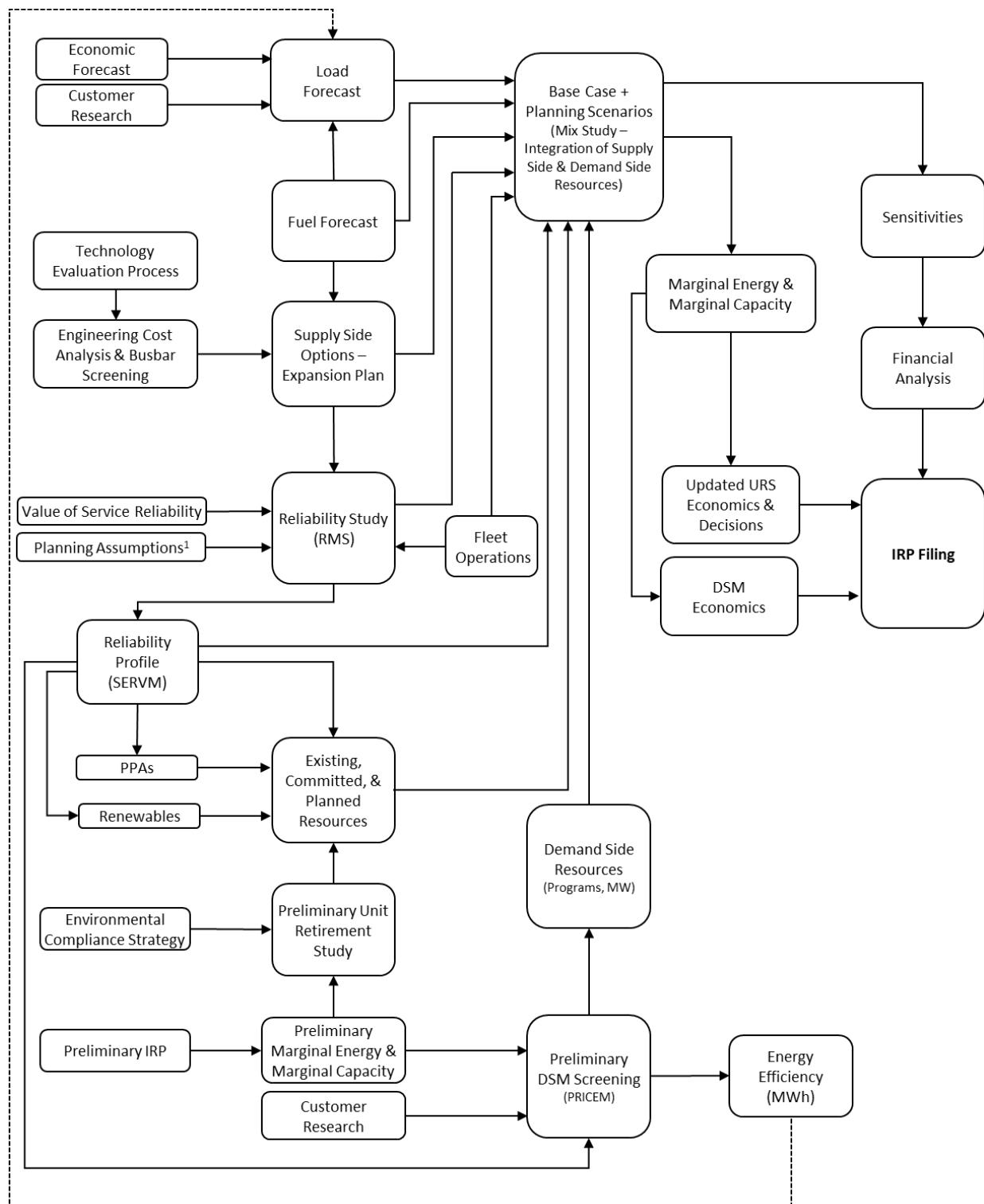
The development of Georgia Power's triennial formal and filed IRP is part of a continuous planning process involving many diverse disciplines and areas of expertise from Georgia Power and Southern Company Services ("SCS"). This process provides for an orderly and reasoned framework through which both demand- and supply-side resources are compared on an equitable basis to develop a plan that provides for reliable and economical electric energy to serve customers' needs over the planning horizon.

4.1. OUTLINE OF THE PROCESS

When developing the IRP, the Company begins by establishing reliability criteria, which are thoroughly reviewed in the Reserve Margin Study in Technical Appendix Volume 1. The Company then applies these criteria to the demand and energy forecasts to determine the amount of capacity that is required to reliably meet forecasted conditions. These factors, combined with projected fuel costs, emissions costs, demand-side programs, and the other inputs reviewed in this IRP, are then used to determine the optimal least cost resource mix (expansion plan).

The Company evaluates both demand- and supply-side options using a common set of assumptions. The decisions made as a result of these evaluations, which are reviewed in CHAPTER 7. and CHAPTER 10. of this IRP, are integrated in the expansion plan using the mix process. The detailed process by which the IRP is developed is shown in Figure 2, and the components of this process are described below.





Notes:

¹ Planning assumptions include inputs such as fuel forecasts, load forecast, and unit assumptions, including renewables

Figure 2: IRP Process

This process results in a plan for demand- and supply-side options to serve customer needs in an economical manner considering reliability, flexibility, and risk. The 2019 IRP presents the results of nine scenario planning cases, as well as several sensitivities, which demonstrate the benefits and flexibility of the Company's strategy. The Company's base case is established using the moderate gas, zero-dollar carbon ("MG0") planning scenario.

4.2. INPUTS TO THE INTEGRATED RESOURCE PLAN

Reserve Margin — This IRP reflects a 16.25% Summer Target Reserve Margin for long-term resource planning decisions as approved in the 2016 IRP Order. In addition, as discussed in CHAPTER 5, as well as Technical Appendix Volume 1 (Reserve Margin Study), the Company is adopting seasonal planning and the implementation of a 26% Winter Target Reserve Margin to accommodate the need for seasonal planning. Sensitivities demonstrating the impacts of a Winter Target Reserve Margin are included in this IRP but are not the basis of decisions reflected in the supply-side strategy.

Fuel Forecast — Both short-term (2019 through 2021) and long-term (2022 and beyond) fuel and allowance forecasts are developed. Short-term forecasts are updated monthly as part of the fuel budgeting process and marginal pricing dispatch procedures. The long-term forecasts are discussed in Technical Appendix Volume 1.

Economic Forecast — IHS Markit's macroeconomic forecast is the basis for inflation and cost of capital estimates. IHS Markit developed a forecast of economic variables and demographic statistics for the state of Georgia. Key descriptive variables from the economic and demographic forecast for Georgia were used to produce the Budget 2019 Load and Energy Forecasts.

Load and Energy Forecasts — The Budget 2019 Load and Energy Forecasts were started in the spring of 2018 and finalized in the fall of 2018. The load and energy forecasting process uses a combination of end-use and econometric analyses and is explained in detail in CHAPTER 6, and in Technical Appendix Volume 1.

Technology Evaluation Process and Economic Screening — Current estimates are needed for costs, spending curves, emissions, and operating characteristics of the types of new supply-side generating units most likely to be added to the System. Such estimates are contained in the Generation Technology Data Book ("GTDB"), which is attached in Technical Appendix Volume 1. Natural gas-fueled simple-cycle CTs (dual fuel option) and CC units are the



generating technologies most likely to be added to the System in addition to renewable generation and DSOs.

Financial Cost and Escalation — Long-term debt and common stock are issued to finance the construction of generating units. The returns demanded by the investment community are affected by perceptions of business risks and the inflation rate. The returns demanded by the investment community and the income tax rates affect the carrying cost of the investment, which can in turn affect the resource capacity mix.

The IHS Markit forecast is the basis of the financing and inflation cost estimates used in the planning process. For the mix analysis, an internally-developed average set of cost escalations was used. Discount analysis using the weighted average cost of capital is applied to place more emphasis on the near term. More information on the discount analysis and the financial parameters used in the mix process is shown in the Resource Mix Study in Technical Appendix Volume 2.

4.3. NEW GENERATING TECHNOLOGIES

The Company continually evaluates established and emerging generating technologies as a starting point in developing its base supply-side plan. The objective is to assess their cost, status of development, safety, operational reliability, flexibility, economic viability, environmental acceptability, fuel availability, construction lead times, and other factors.

The evaluation process:

- Identifies and reviews an expansive portfolio of conventional and new supply-side generation technology options;
- Initiates a preliminary screening analysis based on the maturity of the technology, construction lead times, operating characteristics, financial requirements along with cost uncertainties, environmental impacts, safety of construction and operation, and resource availability;
- Performs a secondary screening analysis of the options that pass the preliminary screening based on scalability, repeatability, site requirements, fuel availability, and environmental characteristics followed by a Levelized Cost of Energy (“LCOE”) economic comparison; and
- Identifies the screened list of technologies to be recommended as expansion options.



Preliminary Screening

The preliminary screening process identifies numerous technologies for strategic assessment, which are listed in ATTACHMENT LL., Table B-1. This strategic and qualitative assessment considers the maturity of the technology, construction lead times, operating characteristics, financial requirements along with cost uncertainties, environmental impacts, safety of construction and operation, and resource availability.

Many technologies from the initial list did not pass the preliminary screening due to their limited applicability to the territory (e.g., Ocean Thermal Generation) or their early stage of development (e.g., magnetohydrodynamics). The results of the preliminary screening are listed in ATTACHMENT LL., Table B-2.

Secondary Screening

Technology options that pass the preliminary screening are then retained for a secondary screening. These options are listed in ATTACHMENT LL., Table B-3. Generic candidate options are identified using qualitative factors such as scalability, repeatability, site requirements, fuel availability, and environmental characteristics. If a technology has potentially desirable economic, environmental, and other characteristics but only under unique circumstances, or if it is not persistently scalable and repeatable, then it will not become a generic candidate nor receive an LCOE evaluation. Technologies that have desirable characteristics under unique application settings, such as specific customer requirements or geographic requirements, are retained separately to be evaluated for future projects should the right set of circumstances present themselves.

Generic candidates identified will undergo additional screening using an LCOE analysis. An LCOE analysis is a common industry method of using screening-level costs to provide an indication of the economic viability of one generating technology option when compared to others. LCOE models include both capital and operating costs relative to the energy produced. The results of the LCOE analysis can then be used to perform a relative comparison of generating units with different operational profiles.

Expansion Planning Process

Candidate technology options retained after the secondary screening are then options for the expansion planning process. These options are shown in ATTACHMENT LL., Table B-4. These



options are further screened using a busbar analysis to identify the economical options over a range of capacity factors. A busbar curve is shown in Figure 4.3.2 in the IRP Main Document Reference Tables section of Technical Appendix Volume 2. Intermittent resources, such as solar and wind, were not included as selectable technologies for the expansion planning model but instead were reflected in the model as planned and committed resources. Such planned resources include the Company's recommended addition of 1,000 MW of renewable resources. It is important to note that recent and proposed renewable additions are selected based on their ability to provide projected energy cost savings to customers, not to specifically meet a capacity need. Capacity additions selected in this process are not determinative of the resources that will ultimately be procured to meet an identified capacity need. Rather they are an indicator of the timing and type of resource that may be required to meet a capacity need. Any identified capacity need will be met in accordance with the Commission's RFP rules.

Planning Scenario Technologies

Through the comprehensive planning process, modified or advanced candidate technology options may be required to meet capacity needs in certain future planning scenarios. However, the technologies required in those future scenarios may not be readily available at this time. Estimates on cost and performance for these future technologies have been included in the expansion planning process to fulfill scenario requirements.

4.4. DEMAND-SIDE ASSESSMENTS

Georgia Power identifies, screens, and assesses potential demand-side programs applicable to its service territory for inclusion in the IRP. This process uses a marginal cost approach to compare the costs with the benefits of each demand-side program. Generation capacity and energy, transmission, distribution, and other costs and benefits are evaluated. The model used to estimate marginal energy cost (AURORA) is the source of the marginal energy cost used in the Profitability Reliability Incremental Cost Evaluation Model ("PRICEM") to evaluate DSM programs. As discussed below, these same marginal costs are used extensively in supply-side evaluations associated with the IRP. Also, technology availability, market characteristics, customer acceptance, and customer response are considered in estimating the potential success, impacts, and costs of the programs. The process is described more fully in CHAPTER 7..



4.5. SUPPLY-SIDE ASSESSMENTS

Georgia Power evaluates supply-side resources for inclusion in the IRP. These evaluations, including the unit retirement studies reviewed in Technical Appendix Volume 2, use a common set of assumptions to derive the marginal cost used in both demand- and supply-side assessments. These assumptions include reliability criteria, the fuel forecast, the economic forecast, and the load and energy forecasts. Supply-side resource decisions are more fully described in CHAPTER 10..

4.6. EXPANSION PLANNING AND THE MIX PROCESS

In this step, the results from the demand- and supply-side assessments are integrated with the planned and committed resources, including renewables. The outcome of this method is a cost-effective mix of demand-side and supply-side resources.

The mix process, or expansion planning process, utilizes dynamic programming techniques to minimize the net present value of the revenue requirements when deriving the least cost expansion plan. To develop the expansion plan, the technologies that passed the detailed screening are further evaluated using the Strategist production cost model. Strategist is widely used throughout the electric industry. Strategist employs a generation mix optimization module named PROVIEW (see ATTACHMENT A.). The major inputs of PROVIEW are: (1) future generating unit characteristics and capital cost; (2) the capital recovery rates necessary to recover investment cost; (3) capital cost escalation rates; and (4) a discount rate.

The optimization process identifies the capacity additions that serve as a guide for the type of capacity that is most economical in a particular timeframe with the given assumptions. The optimization process is essentially a trade-off between fixed costs and variable operating costs for the various generating unit options. The long-term plan for each of the scenario cases, which is further described in the Scenario Planning section below, varies depending on the assumptions for that case. In addition to modeling the planned and committed renewable resources, a mix of gas technologies (CTs and CCs) was selected for the scenario cases through the planning period when capacity was needed to maintain reliability, meet growing customer needs, or to provide fuel-cost savings. The Company's resource needs for the years 2019–2038 based on current assumptions are shown in Tables 4.6.1a through 4.6.3b, Table 4.6.6, and Figures 4.6.4a through 4.6.4b in the 2019 IRP Plan and Reference Tables section of Technical Appendix Volume 2. When Georgia Power acquires resources to meet capacity needs



identified in the IRP, the actual generation resource procured will be selected in accordance with the Commission's RFP rules.

4.7. SCENARIO PLANNING

For the 2019 IRP, the Company presents the results of multiple scenario planning cases that evaluate the impacts of three different fuel price views overlaid with three different carbon views, each estimating the impact of additional pressure on carbon dioxide ("CO₂") emitting generation. Each scenario planning case is a separate and fully integrated resource plan and provides valuable insights into the potential impacts of different combinations of fuel prices and carbon prices over the IRP planning period.

The Company employed a national economic model to evaluate the impacts of different fuel and carbon prices on national and regional economic activity. This national economic model was also used to estimate the impacts of different carbon prices on the price of fuels, particularly natural gas, and to estimate the changes to the electric generation fleet across the United States that result from scenario-specific prices of carbon and fuel. These impacts were extended to develop specific load and energy forecasts for each scenario. The integrated load and energy forecasts were then used as the basis for developing a reliable and economical combination of potential resource options to meet the needs of customers for each scenario.

The Company collaborates with its scenario modeling consultant, Charles River Associates ("CRA"), to produce the long-term fuel price forecasts resulting in the scenario design shown in Figure 3, which is reviewed in detail in Technical Appendix Volume 1.

		CO ₂ Views		
		\$0 CO ₂	\$10 CO ₂	\$20 CO ₂
Fuel Views	High Fuel	HG0	HG10	HG20
	Moderate Fuel	MG0	MG10	MG20
	Low Fuel	LG0	LG10	LG20



Figure 3: 2019 IRP Scenario Design

4.8. SENSITIVITIES

In addition to the nine planning scenarios described above, the Company performed various sensitivity analyses. The following sensitivities to the base case were performed in accordance with the Commission's IRP rules and analyzed in detail in the Resource Mix Study found in Technical Appendix Volume 2:

- Forecast of load:
 - Sensitivity 1 evaluates zero load growth from 2019 levels.
 - Sensitivities 2 and 3 evaluate higher and lower load growth.
- In-service dates of supply and demand resources:
 - Sensitivities 4 and 5 evaluate differing levels of DSOs.
 - Sensitivities 12 through 20 evaluate the impacts of varying in-service dates and amounts of supply and demand resources through the scenario planning cases. In addition to separate fuel price forecasts and estimates of carbon prices, these sensitivities produce separate evaluations of the impacts on the load and energy forecasts, which include effects from demand-side programs and new supply-side resources.
- Unit availability:
 - Sensitivities 6 and 7 evaluate lower and higher forced outage rates.
- Fuel prices:
 - Sensitivities 12 through 20 evaluate the impacts of fuel prices through the scenario planning cases which have three separate fuel price environments and resulting forecasts combined with varying estimates of carbon prices. The scenario planning cases produce separate evaluations of these impacts on the load and energy forecasts, demand-side programs, unit retirements, and new supply-side resources.
- Inflation in plant construction costs and costs of capital:
 - Sensitivities 8 and 9 analyze the impacts of doubling and halving the construction cost escalation rates, respectively.
 - Sensitivity 10 incorporates a higher cost of capital assumption.
- Availability and costs of purchased power:
 - Sensitivity 11 evaluates the impacts of differing availability and costs of purchased power.
- Pending federal or state legislation or regulation:
 - Sensitivities 12 through 20 evaluate the impacts of pending legislation or regulation through the scenario planning cases. The impacts of pending



legislation or regulation can be analyzed by varying estimates of carbon and fuel prices. The scenario planning cases produce separate evaluations of these impacts on the load and energy forecasts, demand-side programs, unit retirements, and new supply-side resources.

- Rate impact analysis:
 - All of the sensitivities analyze the impacts on rates of the varying changes in assumptions. The rate impacts are included in the Financial Review in Technical Appendix Volume 2.

The Resource Mix Study in Technical Appendix Volume 2 and Financial Review in Technical Appendix Volume 2 provide descriptions of these analyses and the impacts of each sensitivity analysis on:

- The timing, amounts, and types of new capacity needed to meet customers' needs.
- The costs associated with meeting the load growth.
-



CHAPTER 5. RELIABILITY

5.1. RESOURCE ADEQUACY

Accepted utility practice requires that electric utilities maintain a sufficient amount of both supply-side and demand-side resources to adequately serve the electricity needs of its customers. The process by which the utility determines the appropriate level of demand- and supply-side reliability on the System is commonly referred to as Resource Adequacy. In Table 4.6.1a through 4.6.3b and Table 4.6.6, and Figures 4.6.4a through 4.6.4b in Technical Appendix Volume 2, the Company demonstrates Resource Adequacy in this IRP, which includes an assessment of the Company's resources, peak demand, and Target Reserve Margins.

5.2. RESERVE MARGIN STUDY

Resource Adequacy requires consideration of not only the uncertainties associated with the demand for electricity, but also the uncertainty associated with the reliability of the resources available to meet that demand. The Target Reserve Margin represents the amount of resources needed above forecasted peak demand to account for these uncertainties. To ensure proper reliability, the Company must evaluate the required reserve margin using a combination of economic and reliability metrics. As such, a reserve margin study is produced in the year prior to each triennial IRP filing to establish a Target Reserve Margin for the System for both the short-term and the long-term planning horizons. The Company performed such a study in 2018, and a report describing the Reserve Margin Study results is included in Technical Appendix Volume 1. The Reserve Margin Study report describes the methodology, metrics, assumptions, and results used to determine the Company's Target Reserve Margin recommendations.

Seasonal Target Reserve Margins

Historically, the Company has only produced a Target Reserve Margin for the summer season because (a) the System peaks in the summer on a weather-normal basis, and (b) the majority of the System's reliability risk has historically been in the summer. However, the 2015 Reserve Margin Study filed in the 2016 IRP reflected a significant increase in winter reliability risks associated with several drivers that had not previously been identified or modeled as part of the reserve margin determination. These drivers include: (1) the narrowing of the difference between summer and winter weather-normal peak loads; (2) higher volatility of winter peak demands relative to summer peak demands; (3) cold-weather-related unit outages; (4) the



penetration of solar resources; and (5) increased reliance on natural gas. The 2018 Reserve Margin Study identified a sixth driver associated with market purchase availability. To address winter reliability issues, the 2016 IRP Order approved an increase in the Target Reserve Margin from 15% to 16.25%. Upon further consideration and examination of the aforementioned reliability risks, the Company will now use a broader seasonal planning process. Given the difference in customer load response as well as differences in both availability and dependability of resources in the summer and winter peak periods, it has become necessary to independently evaluate Resource Adequacy in both the summer and winter peak periods to ensure that System reliability has been adequately evaluated and addressed. Therefore, in addition to establishing a Target Reserve Margin for the summer season (Summer Target Reserve Margin), it is necessary to establish a Winter Target Reserve Margin for the winter season. Technical Appendix Volume 1 contains the Reserve Margin Study, which further explains the need for this Winter Target Reserve Margin.

Defining Target Reserve Margins

The traditional formulation of the Summer Target Reserve Margin is stated in terms of weather-normal summer peak demands and summer capacity ratings according to the following formula:

$$STRM = \frac{TSC - SPL}{SPL} \times 100$$

Where:

STRM = Summer Target Reserve Margin;
TSC = Total Summer Capacity; and
SPL = Summer Peak Load.

By contrast, the Winter Target Reserve Margin is stated in terms of weather-normal winter peak demands and winter capacity ratings per the following formula:

$$WTRM = \frac{TWC - WPL}{WPL} \times 100$$

Where:

WTRM = Winter Target Reserve Margin;
TWC = Total Winter Capacity; and
WPL = Winter Peak Load.



Because winter peak loads are different than summer peak loads and because winter generating capacity can have different operational characteristics than summer generating capacity, the Winter Target Reserve Margin can have the appearance of being higher than the Summer Target Reserve Margin. However, for the same System conditions, both reserve margins represent the same cost and reliability. In other words, for every summer reserve margin there exists an equivalent winter reserve margin that, for the same given System conditions, represents the same cost and reliability.

Target Reserve Margins

After analyzing the load forecast and weather uncertainties, the cost of expected unserved energy, as well as projected generation reliability of the System, the Company plans to maintain the current 16.25% long-term Target Reserve Margin for the System as the Summer Target Reserve Margin to be applied to the summer peak planning season. To address the winter reliability concerns, the Company plans to add a long-term Winter Target Reserve Margin of 26% for the System to be applied to the winter peak planning season. As explained in the 2018 Reserve Margin Study, the planned 26% long-term Winter Target Reserve Margin is consistent with the results of the 2015 Reserve Margin Study if it had generated an equivalent Winter Target Reserve Margin for the System.

For the short-term, the Company plans to increase the Summer Target Reserve Margin from 14.75% to 15.75%, with a commensurate short-term Winter Target Reserve Margin of 25.5%. As explained in the Reserve Margin Study, the gap between the long-term and short-term periods (regardless of season) has reduced from roughly 1.5% to 0.5%. This change is a direct consequence of changing load characteristics and energy efficiency programs that have reduced the overall peak demand response to economic uncertainty.

The benefit of coordinated planning and operations, which allow companies to share resources, is that each Operating Company can carry fewer reserves than the System target. Thus, the Summer Target Reserve Margin that will apply to Georgia Power will be 14.73% over the long-term and 14.23% over the short-term. Likewise, Georgia Power's proposed Winter Target Reserve Margin will be 25.13% over the long-term and 24.63% over the short-term. However, these diversified numbers can change as System load diversity changes.



The Reserve Margin Study Model

The 2018 Reserve Margin Study included in Technical Appendix Volume 1 was performed using the Strategic Energy Risk Evaluation Model ("SERVM"). SERVM is an industry-accepted generation reliability model used for Resource Adequacy analyses and is further described in ATTACHMENT A..



CHAPTER 6. LOAD & ENERGY FORECASTS

Twenty-year forecasts of energy sales and peak demand were developed to meet the planning needs of Georgia Power. The Budget 2019 Load and Energy Forecasts include the retail classes of residential, commercial, industrial, MARTA, and governmental lighting. The baseline forecasts were started in the spring of 2018 and completed in the fall of 2018. A detailed discussion of the territorial energy and load forecasts is set forth in Budget 2019 Load and Energy Forecasts, found in Technical Appendix Volume 1.

6.1. GENERAL FORECASTING AND ECONOMICS OVERVIEW

Both the United States and Georgia experienced robust economic growth from 2013-2017. Over this period, US Gross Domestic Product (“GDP”) growth averaged 2.3% per year, while Georgia experienced growth of 3.1% per year. Also during this period, US employment grew by an average rate of 1.8% per year and unemployment fell from 8.0% to 4.1%. In Georgia, employment growth averaged 2.5% per year and the state’s unemployment fell from 8.7% to 4.5%. In 2018, the unemployment rate fell below 4% for both the United States and Georgia.

Despite steady economic growth in Georgia, Georgia Power’s total retail energy sales have flattened since 2007. Over the 2007-2017 period, weather-normalized total energy sales fell at an average annual rate of -0.2% and remain below 2007 levels. The commercial and industrial classes declined over this same period, down an average of -0.2% and -0.8% per year, respectively. Residential is the only class to experience modest growth, up an average of 0.2% per year over the past ten years. In more recent years, retail sales began to grow due to the strength of the economy in Georgia as evidenced by strong growth in the number of customers. Between 2013 and 2018, total retail energy sales grew at an annual average of 0.5%.

Georgia’s economic growth is expected to continue over the forecast horizon. One factor contributing to growth is that the state remains an attractive place to do business. Businesses are attracted by factors including Georgia’s low cost of doing business and low cost of living, a deep pool of knowledge and technical workers due to its university system, its globally connected airport and transportation infrastructure (e.g., ports and highways), and its business-friendly government policies. Positive demographic trends also drive economic growth in the state. As businesses continue to relocate and expand in Georgia, the state will experience strong employment growth, which will attract new residents. As a result, population growth is projected to remain above the US average.



Additional businesses and a growing population are expected to provide a boost to energy sales. From 2019-2029, total energy sales are projected to grow at an average annual rate of 0.7%. Residential sales are expected to grow by an average of 1.2% per year over this period as the increase in the number of customers outpaces the reduction in use per customer resulting from energy efficiency. Industrial sales are expected to increase at an average annual rate of 1.0% primarily due to the addition of a very large customer. Sales to the commercial class are expected to remain nearly flat, declining by an average of -0.1% per year due in part to increased energy efficiency. Peak demand is expected to increase at an average rate of 0.5% per year. Although Georgia Power is expected to remain a summer-peaking utility over the forecast horizon, the differences between summer and winter peaks are expected to narrow.

6.2. FORECAST ASSUMPTIONS AND METHODS

Budget 2019 assumptions were developed through a joint effort of Georgia Power and SCS. The load and energy forecasts were developed through careful consideration and methodical examination of key demographic and economic variables that historically have been significant indicators of energy consumption. Major assumptions include the economic outlook for the United States and Georgia, energy prices, and market profiles for class end-uses.

The economic forecast gives a description of the economy for the next 20 years and includes many elements of the economy such as gross product, population, employment, commercial building square footage, and industrial production. The economic and demographic forecasts for Budget 2019 were obtained from IHS Markit, a national provider of economic data and forecasts.

The models used to produce both the short- and long-term energy forecasts include a variety of economic and demographic variables as drivers of energy use. Weather, income, employment, historical load data, and industry standards for electrical equipment are among the variables used in the forecasting models. “Normal” weather is defined as the average of Cooling Degree Hours (“CDH”) and Heating Degree Hours (“HDH”) from 1980-2017.

Short-term energy projections for the residential, commercial and industrial classes are based on linear regression models. The short-term and long-term MARTA and governmental lighting forecasts are based on econometric models and information provided by Georgia Power field personnel. The details of these forecast models can be found in Section 4 of the Budget 2019 Load and Energy Forecasts found in Technical Appendix Volume 1.



The long-term forecast models are end-use models. Budget 2019 uses the Load Management Analysis and Planning (“LoadMAP”) model to produce the long-term residential, commercial, and industrial forecasts. The LoadMAP tool is discussed in greater detail in Section 5 of the Budget 2019 Load and Energy Forecasts, found in Technical Appendix Volume 1.

The results of the short-term and long-term models are integrated into a unified forecast. In Budget 2019, the short-term forecast results were used for the years 2019 through 2021 and the long-term results from 2022 to 2038. Additional information on forecasting methodology can be found in Section 3 of the Budget 2019 Load and Energy Forecasts, found in Technical Appendix Volume 1.

Budget 2019 uses the Peak Demand Model (“PDM”) to predict Georgia Power’s weather-normal peak demands. The methodology and assumptions used in the PDM are discussed in greater detail in Section 6 of the Budget 2019 Load and Energy Forecasts, found in Technical Appendix Volume 1.



CHAPTER 7. DEMAND-SIDE STRATEGY

This chapter summarizes the process used to assess demand-side resources for Georgia Power's 2019 IRP filing. Included in this section are:

- A review of significant events since the Company's 2016 IRP filing that are relevant to the screening and assessment of demand-side resources;
- A summary of newly proposed DSM programs, changes to existing programs, and recommended decertification of programs;
- A discussion of the regulatory treatment of DSM program costs and the additional sum; and
- A presentation of the economic results of DSM programs for this IRP.

The identification and evaluation of demand-side resources for inclusion in this IRP involves market considerations, such as customer acceptance and applicability, customer economics, and electric supply economics, using marginal costs in the analysis. As outlined in the 2016 IRP Order, the Company followed the process outlined in the Commission's IRP rules and the DSM Program Planning Approach, which are discussed in more detail in later sections of this filing.

7.1. REVIEW OF SIGNIFICANT EVENTS SINCE THE 2016 IRP

Following the 2016 IRP Order, the following events have influenced Georgia Power's screening of demand-side resources:

2016 IRP Filing Approval

In the 2016 IRP Order, the Commission decertified two programs, amended the certificates of six programs, and certified four new programs in the Company's DSM portfolio. The 2016 IRP Order approved program plans for the following programs:

Residential Programs:

- Behavioral
- EarthCents New Home
- Home Energy Improvement
- Heating, Ventilation, and Air Conditioning ("HVAC") Service
- Lighting



- Refrigerator/Freezer Recycling

Commercial Programs:

- Custom
- HVAC
- Prescriptive
- Small Commercial Direct Install

Program Evaluation Results

As specified in the 2016 IRP Order, process and impact evaluations were to be performed on each of the ten certified DSM programs prior to the 2019 IRP. The Company developed and filed a program evaluation plan with the Commission in 2017 and completed and filed the program evaluation results in 2018.

The Company selected Nexant and Illume to perform these program evaluations. Program evaluations were completed and filed on August 14, 2018. The results were considered in the development of the 2019 IRP, as well as the program plans in the Company's 2019 DSM Certification Application.

DSM Program Planning Approach

Originating from the 2010 IRP Order and reaffirmed in the 2016 IRP Order, the Commission approved the nine step DSM Planning Process (renamed the "DSM Program Planning Approach") that guided the development of the Company's 2019 IRP and DSM Certification plans. In addition, the Company met with the DSMWG eight times in 2017 and 2018 in an effort to collaboratively develop program concepts for the 2019 IRP. The Company met with DSMWG subcommittees in 2018 to discuss DSM program concepts and modeling of a DSM sensitivity case proposed by certain members of the DSMWG. Finally, the Company hosted several conference calls and shared data with the DSMWG in preparation for, and leading up to, the 2019 IRP filing.

Continued IRP Avoided Cost/Fuel Price Decreases

The overall decline in the cost of fuel has reduced the marginal cost of generating energy. As a result, Georgia Power's diverse system has allowed the Company to generate more energy



from the system's natural gas units relative to coal units. The lower cost of fuel not only saves customers money, but also lowers the Company's avoided cost. With these lower avoided costs, the value of each kWh saved as a result DSM participation has declined significantly.

These changes in avoided cost savings have a negative impact on the economics of the Company's current and proposed DSM programs. The Company's Proposed Case highlights that TRC Test results declined and RIM Test results worsened, causing concerns for the Company in its efforts to balance the economic benefits these programs provide for participating customers, with the rate impacts to all customers, whether they participate in the programs or not.

7.2. DISCUSSION OF CURRENT AND PROPOSED DSM PROGRAMS

Residential DSM Programs

In its 2019 DSM Certification Application, the Company requests the following actions or adjustments for the following residential DSM programs:

Residential Program	Status	Action Requested
Behavioral	Existing	Update Program Economics
EarthCents New Home	Existing	Decertify
Home Energy Improvement	Existing	Amend the Certificate
HVAC Service	Existing	Decertify
Power Credit	Existing	No Change Requested
Refrigerator/Freezer Recycling	Existing	Update Program Economics
Specialty Lighting	Existing	Amend the Certificate
Income-Qualified (Crowd Funding)	Proposed	Grant a New Certificate
Residential Thermostat Demand Response	Proposed	Grant a New Certificate

The details regarding current and proposed programs are included in Program Plans filed within the 2019 DSM Certification Application, Docket No. 42311. Additional details regarding decertification requests are listed below.

EarthCents New Home Program. The Company requests decertification of this program due to failing program economics.

HVAC Service Program. The Company requests decertification of this program due to low customer participation rates.



Commercial DSM Programs

In its 2019 DSM Certification Application, the Company requests the following actions or adjustments for the following commercial DSM programs:

Commercial Program	Status	Action Requested
Custom	Existing	Update Program Economics
Midstream Products	Existing	Amend the Certificate
Prescriptive	Existing	Update Program Economics
Small Commercial Direct Install	Existing	Update Program Economics
Behavioral	Proposed	Grant a New Certificate

The details regarding current and proposed programs are included in Program Plans filed within the 2019 DSM Certification Application, Docket No. 42311.

Low-Income Programs

The Company is seeking to certify an income-qualified crowd-funded program within its residential portfolio. The funding currently earmarked toward the Energy Assistance and Savings Program will be repurposed to the new income-qualified crowd funding program.

The Company will also continue to seek \$250,000 annually to fund HopeWorks, which serves income-qualified seniors with a complimentary in-home assessment to identify potential energy saving opportunities, followed by home energy improvements.

Education Initiative

Since 2011, the Company has been delivering the Learning Power curriculum throughout the state of Georgia. The curriculum promotes an understanding of energy and energy efficiency from a grass roots perspective. Lessons have been developed for grades pre-K-12. The method of delivery is highly interactive and hands-on, with lessons delivered by skilled Georgia Power employees, known as Education Coordinators. Education Coordinators are dedicated to a geographic region of the state, with equitable distribution of students and schools among Education Coordinators. Since the launch of the program, the Company has delivered 24,258 programs to 631,516 students through December 2018. Since 2017, approximately 1,439 teachers have been surveyed, and average results over the life of the survey are as follows:

- It was beneficial to their students (99%);



- It increased their students' knowledge about energy efficiency (98%); and
- It improved their students' commitment to energy efficiency (91%).

In addition, Learning Power results in teachers being well informed about energy and energy efficiency after presentations by Education Coordinators.

- Before the presentation, 41% felt very well informed about energy and energy efficiency.
- After the presentation, 95% felt very well informed about energy and energy efficiency.

Energy Efficiency Awareness Initiative

The Company's Energy Efficiency Awareness Initiative promotes the benefits of energy efficiency and educates customers about specific ways to save money and energy. In the 2016 IRP, the Commission approved a dedicated budget for residential and commercial general awareness. The Company seeks continued funding to support efforts that increase general energy efficiency awareness in the residential and commercial markets.

The Company uses direct marketing channels to efficiently reach its customer base. Television, radio, print, internet, billboards, local office advertising, and direct mail are the primary channels used. The Company has developed a number of online tools to enhance customers' learning about energy efficiency. Customers are invited to visit www.georgiapower.com to learn ways to save energy through general energy efficiency information, helpful tips, and specific information about energy efficiency programs offered by the Company. Social media channels such as Facebook, Twitter and YouTube are also used to communicate with customers.

Demand Response Tariffs

For many years, the Company has offered its customers a menu of demand response tariffs, such as:

- Real Time Pricing, which offers customers marginal pricing for incremental load; as prices increase, customers can respond by reducing their demand;
- Demand Plus Energy Credit ("DPEC"), which is an interruptible service tariff that provides commercial and industrial customers with a demand credit for the potential of demand reduction, plus an energy credit when DPEC is called;



- Demand tariffs, which align with the Company's cost of service and encourage demand reduction; and
- Time of Use tariffs, which provide customers with pricing signals during different periods of the day that reflect the marginal cost of the energy in the specific time period (peak and off-peak) and encourage customers to modify their usage accordingly.

Pilot Studies & Budgets

Georgia Power engages in pilot studies to better understand emerging energy efficiency options for the benefit of customers. In the 2016 IRP Order, the Commission approved a \$2.5 million annual budget for DSM and energy efficiency pilot programs. Since 2016, Georgia Power launched five residential pilot programs (Home Automation, Home Electric Review Behavioral, Multifamily Low-Income Smart Thermostats, Residential Bring Your Own Thermostat Demand Response, and Residential Water Heater Demand Response) and two commercial pilot programs (Small Business Behavioral and Indoor Agriculture). The successes and lessons learned from these pilot programs directly influenced the development of the Residential Thermostat Demand Response program and Small Commercial Behavioral programs, which are included in the Company's 2019 Proposed Case.

As part of this 2019 IRP, the Company seeks Commission approval of its proposed \$2 million budget for residential and \$2 million budget for commercial pilots, as outlined in the supporting documents included in Company's 2019 DSM Certification Application in Docket No. 42311. In addition to the general pilot budget, the Company seeks Commission approval of the Income-Qualified Tariff-Based Financing Pilot Program, as suggested by the DSMWG Advocates and discussed in more detail below.

Income-Qualified Tariff-Based Financing Pilot

Georgia Power's Income-Qualified Tariff-Based Financing Program promotes energy efficiency improvements in existing, income-qualified single-family homes, as well as multifamily properties. The 2020-2022 program will be offered as a non-certified pilot directly targeting income-qualified households that are historically under-represented in energy efficiency program participation. The Income-Qualified Tariff-Based Financing Program will be offered to up to two hundred (200) low income residential customers in select, targeted areas of the state with the goal of saving 20% of their baseline household electric energy with an investment of up



to \$7,500 per household. The eligibility criteria for this program will be based on income qualification consistent with the current year's federal guidelines for an income level of 200% of the federal annual poverty level.

Upfront cost is one of the reasons low income customers typically do not participate in energy efficiency programs. Under Georgia Power's Income-Qualified Tariff-Based Financing Program, Georgia Power covers the upfront cost of eligible energy efficiency measures installed, and the customer repays the cost of the energy efficiency upgrades and installation through their utility electric bills via a Commission approved tariff (to be included in Georgia Power's Base Rate case in 2019). Georgia Power is not extending credit to the customer through a loan, rather Georgia Power is offering to pay for eligible energy efficiency upgrades under the terms of a new tariff. Program costs will be recovered through the residential DSM tariff.

The program will be designed to provide net savings for participating customers because the customer's new monthly bill amount, including Georgia Power's monthly charge to recover the cost of the upgrades, will be lower than the customer's monthly energy bill before the upgrades were installed, assuming similar household size, usage, and weather-normalized consumption pre- and post-installation.

The new tariff for the income-qualified program will be associated with the meter at the premises where the upgrades are installed and will remain in force until cost recovery is complete - regardless of a change in occupancy. Once the cost of the upgrades has been recouped, the tariff will be removed from the premises and the customer will enjoy the full benefits of the reduced energy consumption. The cost recovery charge for the upgrades is treated the same as other utility charges on the bill. If a participating customer becomes unable to pay their electric bill, including the cost recovery charge for this program, service will be disconnected in accordance with the Commission Rules. In the event a customer's electric service is disconnected for non-payment, the Company will seek to recover payment through the residential DSM tariff for the amount owed by the disconnected customer for the duration of any lapse in electric service payment. Furthermore, should Georgia Power be unable to fully recover the cost of the installed upgrades under the new tariff, those remaining costs will be included for recovery in the residential DSM tariff.

In addition to the tariff-based offering, the program includes customer education and awareness campaigns, and contractor partnerships and training.



During the pilot, Georgia Power intends to recover only the cost of the energy efficiency upgrades (measures) and installation costs (including labor) through the Income-Qualified Tariff. However, costs for program administration, customer education and awareness campaigns, oversight and evaluation costs will be recovered as part of the residential DSM Tariff. Georgia Power estimates that the cost of the Income-Qualified Tariff-Based Program to be six million dollars as filed in Appendix H of the Company's 2019 DSM Certification Application in Docket No. 42311.

7.3. DSM RESOURCE ASSESSMENT AND INITIAL COST-EFFECTIVENESS SCREENING

Assessment and Screening Methodology

The assessment and screening methodology for DSM measures used in this IRP included identifying DSM measures and programs with input from the DSMWG. Economic evaluations were performed for each measure and program to determine the program cost-effectiveness based on the industry-standard benefit/cost tests and as required by the Commission IRP rules. The tests conducted are the RIM Test, TRC Test, Participants Test ("PT"), Program Administrator Cost Test ("PACT"), and Societal Cost Test ("SCT"). The RIM Test assesses fairness and equity by measuring what happens to customers' rates due to changes in utility revenues and operating costs caused by the program. The TRC Test assesses economic efficiency and societal impact by measuring the net costs of a demand-side management program as a resource option based on the total costs of the program, including both the participants' and the utility's costs. The PT assesses the impact on a program participant by measuring the quantifiable benefits and costs to the customer due to participation in a program. The PACT assesses the net costs of a DSM program as a resource option based on the costs incurred by the program administrator (including incentive costs) excluding any net costs incurred by the participant. The SCT is a variant of the TRC Test and includes an adder to avoided fuel costs to simulate environmental externalities.

The Company met with the DSMWG to discuss and share presentations related to DSM program design details eight times in 2017 and 2018. A smaller sub-group of the DSMWG met and identified the program concepts and measures considered for economic screening in support of the 2019 IRP development. Input from the sub-group participants was used in developing the list of programs and measures within programs to analyze. This list was shared



with the larger DSMWG for solicitation of additional feedback on this process. An agreement among certain parties of the DSMWG was reached regarding some programs to include in the analysis of the DSMWG's Advocacy Case. The preliminary results of the program economic screening were also shared with the DSMWG in November 2018 in advance of the Company's filing.

DSM Program Economic Screening Policy

The Company continues to follow the Commission's economic screening policy outlined in the 2004 IRP Order in Docket No. 17687, which requires the Company to offer a DSM plan that minimizes upward pressure on rates and maximizes economic efficiency. Additionally, the Company's DSM plan treats DSM as a priority resource. In fact, the first step in the Company's IRP process is to reduce the Company's load and energy forecasts by the Proposed Case's energy and demand impacts prior to developing the supply-side alternatives. The Proposed Case's cost-effectiveness results presented herein reflect the continuation of, or modifications to, certain current DSM programs, the addition of new DSM programs, and the decertification of certain existing DSM programs. However, due to declines in avoided costs since the 2016 IRP, the rate impacts for the proposed programs will be larger than those in the DSM programs approved in the 2016 IRP. While the DSM programs continue to provide TRC benefits, such benefits are not as large as in the 2016 IRP due to declining avoided costs. The energy efficiency programs in the Company's Proposed Case for the 2019 IRP achieve an average of approximately \$118 million in TRC benefits while putting upward pressure on rates of approximately \$238 million annually over years 2020 – 2022.

The Aggressive Case sensitivity's cost-effectiveness results are also presented here, as required by the DSM Program Planning Approach. The Aggressive Case sensitivity includes programs from the Proposed Case, but with customer participation at higher penetration levels with higher budgets, as well as additional programs, measures, and associated budgets resulting in significantly higher levels of cumulative energy savings.

At the request of some members of the DSMWG, the Company agreed to analyze the Advocacy Case, which also achieved significantly higher levels of cumulative energy savings. The DSMWG's Advocacy Case is a ramp up of the energy savings targets included in the Company's Proposed Case, as well as additional programs proposed by certain members of the DSMWG.



The higher levels of market penetration in both the DSMWG's Advocacy and Aggressive sensitivity cases ultimately result in substantial upward rate pressure of approximately \$527 million and \$506 million per year, respectively, for years 2020 – 2022. Due to the impact on customer rates, the Company did not use the Advocacy Case or the Aggressive Case, and the Commission should not adopt them either.

Data Development

In developing its list of DSM measures for initial screening, the Company conducted a comprehensive review of technical information sources for demand-side and energy efficiency technologies. This review evaluated the Company's previous IRP filings, as well as reviews of new sources of information, which include industry conferences and trade associations, among others. Additional input was provided by the DSMWG members, some of whom have many years of experience in DSM program development and implementation. Customer feedback was reviewed as a source of information for program additions and improvements. Additionally, Company representatives who work closely with Georgia Power's customers were also surveyed for their input. Information gathered was shared with the DSMWG in program development discussions. The results of the qualitative screening can be found in DMS Program Documentation in Technical Appendix Volume 2.

Residential Technology

More than 100 residential DSM measures were identified for economic screening and possible inclusion in residential programs. These measures provide potential energy savings through:

- Increased energy efficiency for electric equipment;
- Electric space cooling and heating equipment;
- Electric lighting;
- Electric water heating;
- Customer behavior improvements; and
- Heating and cooling savings resulting from improvements to the homes thermal shell.

In addition to specific measures, the building type (single family – new and existing; multifamily – new and existing; or manufactured housing – new and existing) was considered in the economic analysis.



Commercial Technology

More than 125 commercial DSM measures were identified for economic screening and possible inclusion in commercial programs. These measures provide energy savings through:

- Increased energy efficiency for electric equipment;
- Electric space cooling and heating equipment;
- Electric lighting;
- Electric water heating;
- Customer behavior improvements; and
- Heating and cooling savings resulting from improvements to the building's thermal shell.

In addition to specific measures, the building type (the type of customer operation, such as schools or offices) was considered along with the construction type (new and existing) when conducting the economic analysis.

Industrial Technology

No industrial programs are included in the Company's Proposed Case because the Company's experience has shown that industrial customers generally adopt DSM and energy efficiency measures on their own, thus providing benefits to the system and all customers without the need for customer funded incentive programs. Nevertheless, a total of five custom industrial DSM measure categories within one custom program were identified for economic screening and were included as part of the DSMWG's Advocacy Case and Aggressive Case sensitivities. The industrial DSM measures analyzed were:

- Electric space cooling and heating equipment;
- Electric lighting;
- Motors;
- Process equipment; and
- Other industrial categories.

Economic Screening

Energy consumption and savings were calculated for all programs that were passed to economic screening. First, the energy usage characteristics for weather-sensitive HVAC and thermal shell measures were calculated using an engineering simulation model ("EnerSim"). EnerSim is described in ATTACHMENT A.. Second, each potential end-use measure that was



passed to economic screening was then evaluated using PRICEM, which is described in ATTACHMENT A..

The following industry-standard, DSM cost-effectiveness tests were calculated for each measure and subsequent programs: the RIM Test, the TRC Test, the PT, the PACT, and the SCT. Additionally, the Cost of Saved Energy ("CSE"), also referred to as Levelized Cost per annual kWh saved, is provided for each program screened. The CSE is the total cost per kWh of realizing the efficiency improvement. CSE is determined by dividing levelized program costs by the annual energy savings, as shown in the following equation. Levelized program costs are calculated using a Capital Recovery Factor ("CRF"), which incorporates the number of years that the energy savings persist, and an annual discount rate.

CSE Equation:

$$CSE = \frac{\text{Program Costs} (\$) \times CRF}{\text{Annual Energy Savings} (kWh)}$$

Long-Term Percentage Rate Impacts

As required by the 2016 IRP Order, the Company analyzed the long-term percentage rate impact of its DSM Proposed Case and the Advocate and Aggressive sensitivity cases. Please see the DSM Program Documentation section of Technical Appendix Volume 2.

7.4. DEMAND-SIDE PROGRAM DEVELOPMENT

Demand-Side Resource Policy

In the 2004 IRP Order, the Commission directed that proposed DSM plans should minimize upward pressure on rates (negative RIM results) and maximize economic efficiency (positive TRC results). The Commission further directed that the cost/benefit analysis results of each initiative should use the five tests mentioned above and should balance economic efficiency (TRC benefits) with fairness and equity (RIM benefits/cost). This Commission policy was affirmed in subsequent IRPs. The Company applied this same philosophy in analyzing the programs for the 2019 IRP. Consistent with the 2016 IRP Order, the Company adhered to the DSM Program Planning Approach in developing the 2019 IRP.



Twelve-Year DSM Program Plans

The Company has developed twelve-year program plans outlining the implementation details behind each individual program included in the Proposed Case. They are provided in the 2019 DSM Certification Application, Docket No. 42311.

Included in each program plan are the following details:

- Program Summary – outlines the goals of the program;
- Program Structure – outlines the intended participant eligibility, home or facility eligibility, and specific measures and incentives where appropriate;
- Program Implementation – outlines the intended target market, key market players, as well as marketing and outreach plans;
- Program Operation – outlines the intended customer participation process and program administrative procedures; and
- Program Evaluation – outlines the intended performance metrics, expected program budget, cost-effectiveness expectations, as well as plans to develop an independent third-party evaluation plan after programs are approved.

Each of the twelve-year DSM Program Plans allows for ongoing review and modification of program design features through regular program monitoring. In addition, a formal program evaluation plan at the end of the program cycle is conducted to maintain cost-effectiveness. Any significant changes to program design in support of market conditions or program economics will be included with ongoing reports filed with the Commission, program evaluation filings, and/or IRP updates. Additionally, as new measures and technologies evolve during the twelve-year filed program life, the Company may add such measures to these programs. Any new measures being added will follow the same economic screening process as those approved by the Commission, and the Commission would be made aware of any additions prior to the Company offering the new measures to customers as required.

7.5. REGULATORY TREATMENT OF DSM PROGRAM COSTS AND THE ADDITIONAL SUM

The Company requests the continued collection of costs for all approved and certified DSM programs and activities through the existing Residential and Commercial DSM tariffs. These tariffs will be filed as part of the Company's 2019 base rate case and would be implemented



with any approved change in rates on January 1, 2020. The Company also requests the continued collection of an additional sum amount for certified energy efficiency programs with energy savings through these tariffs pursuant to a revised additional sum calculation methodology presented in the Company's DSM Certification Application in Docket No. 42311.

7.6. SUMMARY OF DSM CASES

Proposed Case

The energy efficiency programs in the Company's Proposed Case for the 2019 IRP achieve an average of approximately \$118 million in TRC benefits while putting upward pressure on rates of approximately \$238 million annually over years 2020 – 2022. The Company is concerned that these results do not strike the balance needed when considering energy efficiency programs but plans to continue the established energy efficiency programs approved in the 2016 DSM Certification filing, modified as proposed above, to achieve approximately the same levels of energy savings that are currently being achieved. The Company plans to continue the programs at this time based on the desire to minimize market disruption, to continue meeting customers' expectations, and to maintain positive relationships with vendors performing qualified program improvements. The Company plans to monitor program costs and economics from 2020 through 2021 and will be prepared to modify programs if significant upward pressure on rates continues.

The Company's DSM portfolio included in the 2019 IRP consists of currently certified programs as well as new programs, modified based on data gathered in the implementation phase, as well as input from the DSMWG and an independent third-party evaluation. The Proposed Case will continue to enhance these programs as more information becomes available relative to market penetration and customer feedback through an ongoing evaluation process. The Company will keep the Commission fully informed of potential changes to programs through notification to, or approval by, Commission Staff, as required.

The Company's Proposed Case summary economics are provided in the DSM Program Documentation section of Technical Appendix Volume 2. As part of the DSM Program Planning Approach, the Company agreed to calculate the generation avoided costs for its DSM change case using its system tool. The avoided generation costs for the Company's Proposed Case from the system tool were not significantly different than the avoided generation costs obtained from PRICEM. Also, the avoided generation costs for the DSMWG's Advocacy and Aggressive



sensitivity cases from the system tool were not significantly different than the avoided costs obtained from PRICEM.

DSMWG Advocacy Case

The DSMWG Advocacy Case was developed as a sensitivity case to the Company's recommended DSM plan and is based on requests made by certain members of the DSMWG. The Company presents the results of this case for informational purposes.

If the DSMWG Advocacy Case is implemented, the portfolio would put additional upward pressure on rates of approximately \$527 million on average annually for years 2020 – 2022. Over the 2020 – 2031 program years evaluated within this sensitivity case, upward pressure on rates would increase on average by about \$708 million annually (NPV over the life of the measures). The Advocacy Case includes a ramp up of the Company's Proposed Case, as well as additional programs proposed by certain members of the DSMWG, which included program assumptions that the Company does not agree with. Therefore, the Company does not recommend approval of the DSMWG Advocacy Case.

The DSMWG Advocacy Case summary tables are provided in the DSM Program Documentation section of Technical Appendix Volume 2.

Aggressive Case

The Aggressive Case was developed to represent an aggressive DSM sensitivity and was developed as outlined in the DSM Program Planning Approach. It serves as a reference point to estimate the maximum achievable potential for increased energy efficiency and the impacts of such aggressive adoption of DSM. This increased energy efficiency comes at a high cost to customers. The impacts from the Aggressive Case ultimately result in average annual upward pressure on rates of approximately \$506 million for years 2020 – 2022. Over the 2020 – 2031 program years evaluated within this sensitivity case, upward pressure on rates would increase on average by almost \$563 million annually (NPV over the life of the measures). The Company does not recommend approval of the Aggressive Case.

The Aggressive Case summary tables are provided in the DSM Program Documentation section of Technical Appendix Volume 2.



7.7. RECOMMENDED DSM ACTION PLAN

In summary, the Company's recommended DSM action plan includes the following items detailed in Section 7.2:

- Implementation of the six residential and five commercial DSM programs;
- Continuation of the residential Power Credit program;
- Continuation of the Education and Energy Efficiency Awareness initiatives;
- Continuation of pilot studies and approval of annual pilot budget; and
- Approval of the Income-Qualified (Tariff-Based Financing) pilot and budget.



CHAPTER 8. RENEWABLE RESOURCES

As part of Georgia Power's overall strategy to deliver clean, safe, reliable, and affordable energy from a diverse fleet of generation resources, the Company continues to collaborate with the Commission and renewable stakeholders to develop a nationally recognized portfolio of renewable projects and programs, including solar, wind, and biomass resources. Georgia Power's steady and measured approach to grow renewable resources includes the procurement of renewable resources from both small and large-scale generators, the development of Company-owned solar generation facilities, and implementation of customer-focused renewable energy programs, all designed to meet customer renewable energy needs and create projected long-term savings. As a result of these efforts, energy is now being delivered to Georgia Power customers from more than 1.6 GW of renewable resources, with more than 1.5 GW of additional renewables projects under contract or development and anticipated to be online by the end of 2021.³

Since the 2016 IRP, the state of Georgia and Georgia Power Company have been recognized by both the Smart Electric Power Alliance ("SEPA") and the Solar Energy Industries Association ("SEIA") as a top producer of solar in the country. Most recently, SEPA awarded the Company with the 2017 "Top 10 Utilities by Cumulative Solar Capacity," and SEIA ranked Georgia 10th in cumulative solar capacity. Through the leadership of the Commission and collaboration with the renewable energy community, Georgia has set a national standard for responsible renewable energy growth and proven that such growth in renewable energy can be achieved without a mandate or RPS. This approach has been developed working closely with the Commission and Commission Staff to deliver cost-effective and customer focused renewable energy, while abiding by the principles of customer fairness, applying accurate costs and benefits, and maximizing value for customers by using market driven and competitive procurement practices. Figure 4 illustrates the historical and expected cumulative renewable capacity for Georgia Power through 2021, by resource type.⁴

3 Georgia Power purchases only the null energy output from some renewable generating facilities that have contracted to sell energy from their facilities to Georgia Power. The ownership of the associated RECs is specified in each respective PPA and the party that owns the RECs retains the right to use the RECs. Georgia Power does not report emission reductions from the null energy purchased through PPAs that do not bundle the RECs for sale to Georgia Power.

4 All current and forward-looking online and contracted solar capacity numbers are shown in alternating current ("AC") or direct current ("DC") values, based on program reporting.



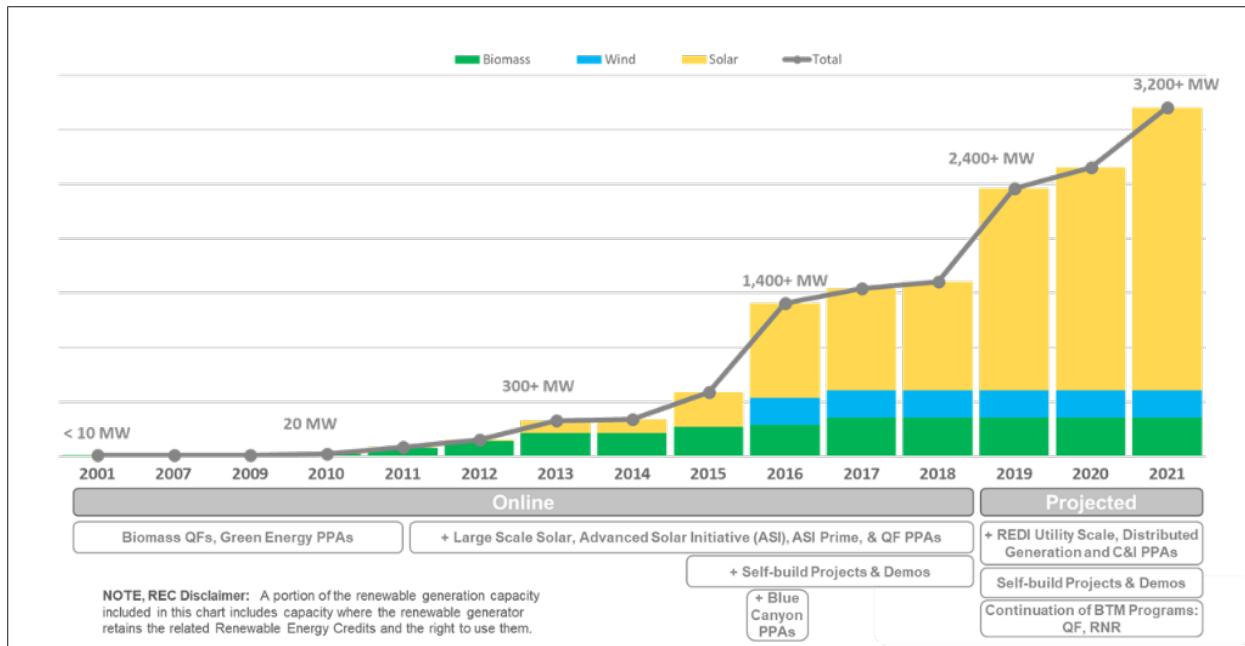


Figure 4: Historical and expected cumulative renewable capacity for Georgia Power

While industry comparisons are an important measure of success, Georgia Power's greatest accomplishment with respect to renewable development is effectively responding to customer needs, while creating projected long-term savings. Georgia Power has maximized the benefits to customers by maintaining a disciplined approach to integrating renewable resources, which utilizes competitive procurements and application of the RCB Framework to procure renewable resources below projected avoided costs.

Georgia Power continually monitors market trends and technology advances to implement innovative and customer-focused renewable programs. As an example, the Company has taken advantage of steadily declining solar costs by making incremental and disciplined procurements of renewable generation. As the cost of renewable generation continues to decline, customer interest, investment, and support of renewables continues to grow. Customers with an interest in sustainability are leveraging Georgia Power's renewable programs to assist in achieving those goals. Georgia Power remains committed to meeting customer needs through renewable programs that provide value from market-based procurement strategies aimed at maximizing long term projected avoided cost savings.

Since the 2016 IRP, Georgia Power completed the Advanced Solar Initiative ("ASI") and ASI Prime programs. These procurements amounted to 733 MW of solar resources, of which 555

MW are utility scale and 178 MW are DG. The successful implementation of these programs was used as a guide for the design of the REDI programs that were approved in the 2016 IRP. The REDI programs currently being implemented include competitive procurements of 1,050 MW of utility-scale renewable resources, a competitive procurement of 100 MW of DG solar resources, and 50 MW of customer-sited DG solar resources. For large C&I customer participants, Georgia Power introduced the C&I REDI program, which competitively procured an additional 177.5 MW of solar resources. C&I customers also have the option to participate in Georgia Power's Simple Solar program, a solar renewable energy credit ("REC") purchasing program. Residential customers can participate in the Simple Solar program and have the added option to subscribe to blocks of energy through Georgia Power's Community Solar program. The Company continues to support and engage with all customers by offering solar analysis and guidance on their decisions for pursuing renewable options. Finally, the Company is developing a portfolio of self-build renewable resources in Georgia and has already completed projects at Fort Benning, Fort Gordon, Fort Stewart, Kings Bay, and the Marine Corps Logistics Base in Albany. Following the 2016 IRP, Georgia Power is developing seven additional solar facilities on military bases and college campuses, including projects at Robins and Moody Air Force Bases and Fort Valley State and Georgia College and State Universities, as well as the Community Solar facilities in Comer, Guyton, and Waynesboro.

Through direct feedback from the Company's customers and based on market research completed in late 2018, Georgia Power confirmed that customers across all classes are generally supportive of the Company's approach to renewable procurement and programs. As such, the Company plans to continue working with the Commission, customers, and other stakeholders to design programs that build upon the Company's previous lessons learned and best practices to deliver industry-leading, customer-focused renewable solutions. This experience is applied to program design in accordance with Georgia Power's three basic renewable energy principles: (1) maintain customer fairness by minimizing cross-subsidization of programs across customer groups; (2) appropriately value costs and benefits of renewable energy as defined by the RCB Framework; and (3) generate maximum value for customers by focusing on market-based procurement strategies. With these principles in mind, Georgia Power intends to continue disciplined growth in the rapidly evolving renewable energy sector, consistent with prior Commission-approved programs and initiatives.



8.1. NEW RENEWABLE RESOURCES

The Company proposes a procurement strategy that will maintain the steady growth of renewable generation in Georgia and build upon the success of the C&I REDI program, which has been recognized as an effective design that aligns customer needs with competitive procurement of utility-scale renewable resources. Additionally, Georgia Power will competitively procure renewable DG resources and enhance existing programs with minor modifications to maximize value for customers. The combination of these modified programs and continued procurement is designed to complement the Company's IRP for the benefit of all customers. Consistent with the previous practice, energy will be procured competitively, below the Company's projected long term avoided cost. The costs to administer and implement renewable energy programs will continue to be recovered through the fuel clause. As discussed in the supply-side strategy in CHAPTER 10., the Company also proposes to investigate battery energy storage applications deployed both independently and in tandem with intermittent resources, to enhance Georgia Power's understanding of the impacts of energy storage on the system. To support this learning objective, Georgia Power proposes to add 50 MW of self-build storage capacity.

Utility-Scale Procurement Strategy

Georgia Power proposes to procure energy from up to 950 MW of utility-scale renewable resources greater than 3 MW alternating current ("AC") in size, below Georgia Power's projected avoided costs through the CRSP program. Discussed in further detail below, the CRSP program will be designed to build upon the success of the Company's previous C&I REDI program and will procure resources available for subscription by both existing and new customers. The CRSP program will simultaneously help participating customers meet their sustainability goals and deliver projected long-term savings for all Georgia Power customers.

The Company proposes to issue two RFPs for utility-scale renewable resources achieving commercial operation by 2022 (2022 Renewable RFP) and 2024 (2024 Renewable RFP) available for subscription by both new and existing customers through the CRSP program. By offering existing large customers the opportunity to subscribe to a portfolio of up to 500 MW of new renewable resources, the Company seeks to satisfy the increasing demand from customers with specific goals to support renewable energy. Additionally, up to 450 MW of new renewable resources will be available for subscription from customer load additions greater than



25 MW, providing Georgia Power with an additional economic development incentive to attract large companies who desire to support renewable energy when locating to Georgia. This procurement strategy mitigates the cost risks to non-participating customers, as the subscribing customers will cover the full cost of the renewable PPAs during their participation.

The Company will select the resources that produce the most savings for customers when compared to the projected avoided costs utilizing the RCB Framework. As authorized by statute, the Company requests to receive a levelized additional sum of 10% of the net present value of projected benefits from the PPAs. The Company will take ownership of all RECs produced by these facilities, to retire either on behalf of the CRSP participants and/or all Georgia Power customers. Bid fees will be established to recover all RFP-related administrative and technical evaluation costs incurred by the Company. The Company will work with Commission Staff and interested stakeholders to further develop the timeline for the RFPs. Additional details about the CRSP program are detailed below in the Renewable Programs section.

Distributed Generation Procurement Strategy

Distributed Generation continues to be part of the Company's procurement strategy. Georgia Power proposes to procure up to 50 MW from renewable DG resources sized less than or equal to 3 MW AC. The Company will procure these resources through a competitive RFP at prices below Georgia Power's projected avoided costs. The Company requests to receive a levelized additional sum of 10% of the net present value of projected benefits realized from the PPAs. Bid fees will be established to recover administrative and implementation costs incurred by the Company.

8.2. RENEWABLE PROGRAMS FOR CUSTOMER PARTICIPATION

Customer Renewable Supply Procurement (CRSP)

Based on the success of Georgia Power's C&I REDI program, the Company plans to expand the customer subscription model to the overall utility-scale renewable procurement efforts to offer a large portfolio of resources available for subscription. The CRSP program, as proposed by the Company, will build upon many of the C&I REDI program design elements.

As proposed, participating customers will enter into a customer agreement specifying the pricing, terms, and conditions of their participation in the CRSP tariff. The Company will credit participating customers based on the actual hourly marginal energy cost of incremental



generation multiplied by the amount of energy produced by the CRSP facilities. The monthly fee to participate in CRSP will be in addition to the customer's regular monthly electric service payments. The associated franchise fee and applicable taxes will continue to be applied to the entire bill. Interested customers will be given the opportunity to submit a Notice of Intent ("NOI") identifying their proposed subscription level in MW, contract term length, and other requirements related to their interest in the program. The Company proposes a required NOI participation fee to offset the costs of pre-program implementation.

Any portion of the total 950 MW of renewable capacity that is not subscribed by participating customers (whether existing or new) will be procured to serve all Georgia Power customers.

Participation Requirements for Existing Customers (Up to 500 MW):

Existing customers with a minimum annual peak demand of 3 MW at one account (or an aggregate of GPC accounts under common control) may participate and can subscribe in an amount up to 100% of their preceding year's total annual energy consumption for each of the customer's qualifying premises aggregated to meet the eligibility criteria. If the level of existing customer capacity interest exceeds the available MW for each solicitation, Georgia Power will allocate subscriptions among participating customers who complete the NOI process.

Participation Requirements for New Load Customers (Up to 450 MW):

The C&I REDI program generated interest from many customers, including many large prospective economic development customers that may choose to expand or to locate new facilities in Georgia. These customers have stated that the availability of renewable energy options is a significant factor in determining the location and electric service provider to serve new load. To help attract this new load, Georgia Power will offer up to 450 MW of renewable generation for subscription by customers adding incremental, new load of 25 MW or greater.

Georgia Power will file further program details and timelines for the CRSP program following the approval of the 2019 IRP.

Simple Solar

Georgia Power's Simple Solar program was introduced and approved through the 2016 IRP. The program provides an option for all customers to support the growth of solar. Customers can participate by matching either 50 or 100 percent of their monthly energy usage with RECs for an



additional 1¢ per kWh. The Simple Solar program also provides a cost-effective option for large C&I customers interested in supporting solar through the Large Volume discounted pricing, based on their specific renewable energy needs. Currently, Large Volume pricing starts at 1¢ per kWh, per month for matching the first 50,000 kWh of RECs; 0.8¢ per kWh, per month for the next 100,000 kWh of RECs; 0.6¢ per kWh, per month for the next 200,000 kWh of RECs; and 0.5¢ per kWh, per month for all kWh of RECs exceeding that amount. As customer interest in the Simple Solar program continues to grow, Georgia Power has identified the need for greater flexibility for its large customers. The Company proposes to revise the Simple Solar Tariff Large Volume Purchase Option pricing to change the 0.5¢ per kWh per month tier for the next 1,650,000 kWh of RECs and add a new additional pricing tier where all remaining kWh of RECs exceeding that amount to be priced at the current REC market price offer at the time of contract. The additional market pricing tier is designed to continue to collect the full administrative costs of the program while preserving the ability to offer more competitively-priced solar RECs for energy-intensive users. One-time purchases will also remain available under the Special Event Purchase Option.

Behind-the-Meter Options

The Company will continue to offer analysis and support for all customers interested in installing customer-sited generation. Customers will continue to have the option to sell renewable energy to Georgia Power as Qualifying Facilities (“QF”). In addition, customers can sell the output of solar photovoltaic, fuel cell, or wind turbine distributed generation facilities through the RNR tariff. Georgia Power has interconnected more than 2,000 solar projects, including customers who choose to offset energy usage with behind-the-meter solar installations, through RNR or as a QF. As approved in the 2016 IRP, the Company is implementing the requirement to execute interconnection agreements for customers with DG installed on their premises who choose not to participate in the Company’s programs. This requirement allows Georgia Power to accurately account for all generation connected to its infrastructure and ensure safety and reliability.

Customer Engagement

Georgia Power seeks to add value to all customers by providing industry-leading customer service related to renewable customer engagement activities. In late 2013, the Company created the Renewable Development department specifically to develop, manage, and support renewable initiatives. As customer interest in solar and renewable options continues to grow, the



Company has enhanced its ability to provide support and education to customers interested in renewable energy. This customer support function seeks to deliver a cohesive education process for customers interested in solar. Once communication has been established, Georgia Power's Renewable Development team provides comprehensive support for customers, including guidance on renewable program options, including Community Solar, Simple Solar, and solar installation with buy-back programs. Upon request, customers can receive a solar installation cost estimate from independent solar installers or from Georgia Power's unregulated business unit, Energy Services. Renewable Development has fielded thousands of calls and emails from customers interested in Georgia Power's solar programs and has completed more than 1,700 customized analyses with guidance on buy-back program participation. Georgia Power's Renewable Development team is committed to providing accurate and useful information about various programs to help customers make their best solar decisions.

8.3. RENEWABLE COST BENEFIT FRAMEWORK

An important principle underlying the growth of renewable energy at Georgia Power is to accurately calculate and apply appropriate costs and benefits created by the energy delivered by a renewable generator. The RCB Framework is critical to ensure fairness for those generators and the customers for whom Georgia Power procures renewable energy. The Company first filed the framework for determining the costs and benefits of renewable resources in Georgia in its 2016 IRP. In December 2016, after extensive collaboration with Commission Staff to refine and clarify the RCB Framework, the Commission approved the Joint Recommendation for the continued implementation and application of the RCB Framework. In June 2017, the Company received Commission approval to apply the RCB Framework to behind-the-meter solar technologies, including, but not limited to, use in the determination of the RNR tariff for solar technologies. The Company continues to apply the RCB Framework to the evaluation of renewable projects and pricing for programs offered in the 2019 IRP. As the RCB Framework is a living document, the Company has made several improvements to the RCB Framework document in the 2019 IRP to provide additional clarity as needed, consolidate and simplify where appropriate, and to document the history of the RCB Framework since the 2016 IRP. The Company has moved one component from "Placeholder" status to "Exclude" status and no new components are recommended for inclusion in the RCB Framework at this time. In addition to the RCB Framework document, the Company has filed three additional documents – "The Costs and Benefits of Distributed Solar Generation in Georgia," "The Costs and Benefits of Utility Scale Fixed Tilt Solar Generation in Georgia," and "The Costs and Benefits of Fixed and



Variable Wind Delivered to Georgia” – which provide illustrative quantifications of the costs and benefits (excluding acquisition costs) of such technologies on a per kWh basis under certain specified scenarios. The RCB Framework, and the supporting documents are included as part of the 2019 IRP in Technical Appendix Volume 2.

8.4. UPDATE ON 2016 IRP INITIATIVES

The Company continues to implement industry leading renewable programs and initiatives as approved in previous IRPs, due in large part to the leadership of the Commission and the constructive collaboration with industry stakeholders. Georgia Power seeks to improve the design and implementation efficiency of programs with each phase of development to deliver maximum benefit to all customers and stakeholders.

REDI Utility-Scale Procurement

As approved by the Commission, the REDI Utility-Scale procurement of renewable energy from 1,050 MW of capacity was split into two separate RFPs, each seeking 525 MW of renewable resources greater than 3 MW. The first phase of the solicitation was issued in 2017, and the second phase is currently underway. All resources procured through these solicitations must be acquired at prices below the Company's long-term projected avoided costs. The first RFP required projects to achieve commercial operation in 2018 or 2019. From this solicitation, Georgia Power entered into 30-year PPAs with three suppliers for a total of 510 MW of in-state solar capacity, with an average price of 3.6¢/kWh. This solicitation was an “all source” request for any eligible renewable resource, including renewable resources coupled with energy storage; however, the resources that provide the most value to customers proved to be in-state solar facilities without storage. Following the 2018/2019 REDI RFP, Georgia Power carried forward the remaining 15 MW of capacity to the 2020/2021 REDI RFP, bringing the target for the second utility-scale solicitation to 540 MW. The second solicitation bid period was open from December 10, 2018 through January 15, 2019 and requires facilities to achieve commercial operation in 2020 or 2021. The Company has started the bid evaluation process.

C&I REDI

In order to supply the C&I REDI Program, Georgia Power utilized the existing bids from the Reserve List of the 2018/2019 REDI Utility-Scale RFP. That process yielded additional PPAs with two providers, totaling 177.5 MW. Customers interested in participating in the program were



required to provide a NOI indicating the amount of program capacity for which they would like to contract. As a result of the NOI process, four customers expressed interest for more than 400 MW of capacity, which exceeded the program supply target amount of up to 200 MW. Ultimately, Georgia Power entered into C&I REDI Customer Agreements for the pro rata portion of the program capacity that each participant requested through the NOI process. The facilities to supply this program are scheduled to come online in 2019 and 2020.

REDI Customer-Sited DG

As approved in the 2016 IRP, the REDI Customer-Sited DG program sought to fulfill a 50 MW portfolio of DG solar resources, which was combined with the remaining unsubscribed MW from the previous ASI DG and ASI Prime DG solicitations for a total target of 61.62 MW. Eligible DG resources were to be sized greater than 1 kW up to and including 3 MW DC and to be sited on or adjacent to an existing customer's premises. The application period was open from November 1 through November 30, 2017 and yielded more than 151 MW from 143 applications. Georgia Power evaluated more than 80 MW of projects for the Selection List. These projects subsequently went through a more detailed analysis in which the Company evaluated the interconnection requirements before offering contracts. Since that time, several developers have withdrawn projects from the program for a variety of reasons, even after the PPAs had been executed. Some of the REDI Customer-Sited DG program projects are still under construction, and the current program yield is approximately 47.91 MW from 34 projects.

REDI DG RFP

As part of the 2016 IRP, the Commission approved the REDI DG RFP which sought to procure energy from 100 MW of solar resources. The 100 MW were combined with the remaining unsubscribed capacity from previous DG solicitations for a target of approximately 113 MW. This innovative program used competitive bidding from solar facilities from 1 kW up to and including 3 MW AC in size. The facilities are required to achieve mechanical completion in 2019. Bid pricing for the REDI DG RFP, which included the price for the solar output plus the project's interconnection cost, could not exceed the Company's long-term projected avoided cost. The results of this solicitation are still being analyzed at the time of this filing and will be shared with the Commission as soon as practicable.



Simple Solar Program

As discussed in greater detail in section 8.2 above, Georgia Power's Simple Solar program was approved in the 2016 IRP. This program is designed to allow all customers to support and foster the growth of solar energy by enabling Georgia Power to purchase and retire RECs generated from solar energy resources. As of January 2019, there are 1,172 customers enrolled in the program. In 2018, customers purchased 57,734,464 kWh of RECs. Georgia Power will continue employing a broad range of marketing efforts to create additional awareness and increased participation in 2019.

Community Solar Program

The development of a 3 MW Community Solar program was approved through the 2016 IRP. Following the 17th Vogtle Construction Monitoring ("VCM") proceeding, this program was expanded to include an additional 5 MW, creating a total of 8 MW of program capacity. The Community Solar program is designed to provide residential customers an opportunity to purchase a monthly subscription, in exchange for receiving a bill credit based on the solar facilities' production. Subscriptions are purchased in 1 kW block increments. Currently, the Company has developed 2 MW of supply from the Comer Community Solar Facility and anticipates the remaining 6 MW of supply to be online and available for subscription in 2019. Currently, 1,472 blocks out of the 2,000 blocks available are subscribed, representing 850 unique customers. Georgia Power will continue employing a broad range of marketing efforts to create additional awareness and increased participation to coincide with commercial operation of the new facilities this year.

Self-Build Renewable Projects

As approved in the 2016 IRP, the Company is developing self-build solar assets at Robins and Moody AFB, Georgia College and State University, and Fort Valley State University. Additionally, the Company is developing an 8 MW portfolio of solar to supply the Community Solar Program as described above. Approved self-build capacity of approximately 15 MW remains uncommitted, and the Company continues to pursue the development of this capacity at viable locations in Georgia.



8.5. UPDATE ON DEMONSTRATION PROJECTS UNDER DEVELOPMENT

The Company remains committed to research and development (“R&D”) while assessing the overall market opportunities for deployment of new renewable resources. As such, the Company conducts meaningful demonstration projects that increase its understanding of changing renewable technologies and applications.

High Wind Study

The High Wind demonstration project approved in the 2016 IRP allows the Company to further study the potential for higher hub height wind resources in Georgia through the purchase, siting, and installation of wind measurement instrumentation that will monitor high elevation wind data at multiple locations. Thus far, the Company has procured components, identified locations for the installation of Windcube v2 LiDAR Remote Sensor wind measuring devices, and deployed the devices at the identified locations. Currently, Georgia Power is gathering information to measure wind potential. Details on this demonstration project are provided to the Commission through regular, quarterly reports.

Closed Ash Pond Solar

In the 2016 IRP, the Commission approved the development of up to 10 MW of solar generation at Company-owned coal-fired generating facilities. The scope includes evaluation of different technologies, including traditional and non-traditional racking systems. The output of the project(s) will be interconnected to the site’s existing infrastructure and will serve Georgia Power customers. The project(s), pending Georgia Environmental Protection Division (“EPD”) approval, will provide the Company with a hands-on, detailed understanding of the requirements to permit and build solar generation facilities on closed solid waste sites, remediated sites, and/or underdeveloped plant properties.

The Company plans for these projects be located at closed ash ponds at Plant McDonough and Plant Hammond, with preliminary plans included as part of the ash pond closure permits, which are currently under review by the Georgia EPD. At the time of this filing, project expenditures have been minimal as permitting is not yet complete. The Company will continue its efforts to obtain permits for these facilities and, with EPD regulatory approval, proceed with siting, infrastructure, and design plans for the project. In addition, the Company is deploying an initial 38 kW installation at Plant McDonough which is expected to be operational in early 2019. This pilot project is specifically testing ash pond closure cover systems that could substantially



increase the closed ash pond acreage available for photovoltaic (“PV”) installations. The Company will monitor the performance of the ash pond closure cover system and report to the Commission the results and potential inclusion in future solar generation development on ash ponds.

Right of Way Solar

In the 2016 IRP Final Order, the Commission required Georgia Power to commence a fixed-tilt demonstration project to be located in the interstate right-of-way along Interstate 85, in partnership with MZC Foundation (d/b/a “The Ray”) and the Georgia Department of Transportation (“GDOT”). Georgia Power has worked with the project partners to develop an 800 kW AC solar generation facility located at the intersection of Highway 27 and Interstate 85. Georgia Power has contracted with an EPC provider, which is currently completing the construction engineering package. Additionally, the Company is in the process of obtaining the appropriate permits and agreements from GDOT and the Federal Highway Administration to gain full site control and proceed with construction of the facility. The Company anticipates that the project will achieve the required COD of December 31, 2019.



CHAPTER 9. HYDROELECTRIC

Georgia Power operates 18 hydro facilities and has an ownership interest in a 19th – Plant Rocky Mountain – with a total of 71 generating units in Georgia. All but one of these facilities – Plant Estatoah – is licensed by the Federal Energy Regulatory Commission (“FERC”) under the Federal Power Act. In all, Georgia Power has ownership rights to 1,107 MW of hydro capacity. The following information details a review of the fleet, relicensing schedules, and the estimated risk of environmental challenges to continued operation associated with these facilities.

9.1. CONTINUED INVESTMENT IN THE HYDRO FLEET

Georgia Power has conducted an extensive review of its hydro fleet and determined that numerous, essential components at several facilities are at or near the end of their useful lives and require additional investment to continue operation. These investments will allow these resources to operate for at least another forty years while improving the efficiency, integrity, and safety of the hydro fleet while preserving valuable carbon-free resources for the long-term benefit of all customers.

The need for additional investment is demonstrated by recent performance issues, facility conditions, and operational experiences at several units. Performance issues due to turbine failures, generator failures, and penstock corrosion lead to long-term forced outages and warrant additional investment. These investments would address required maintenance and upgrades related to issues such as cavitation damage to turbines, aging head gate operators, aging relays and gauges, and cracking in wicket gates, and would allow for needed generator rewinds and replacement of turbines, cranes, piping, oil-filled circuit breakers, spillway gates and flashboards, and other equipment critical to operation. Moreover, replacing leaking spillway gates, replacing flashboards with modern gates, and replacing wicket gates will reduce current energy losses from these plants and improve their performance.

The hydro fleet’s unique operating characteristics support continued renewable resource integration by compensating for the intermittent nature of renewable generation, specifically wind and solar. These characteristics, such as quick start capability, high ramp rates, and pumped-storage abilities are superior to the capability of other dispatchable resources. Several hydro units have experienced increased outage rates (both planned and unplanned) due to the performance issues mentioned above. At the same time, the amount of intermittent renewable resources on Georgia Power’s system has continued to grow.



The hydro fleet also provides other unique benefits to the state of Georgia, including recreational opportunities, fish and wildlife enhancements, and local economic development. For the Company to continue providing these benefits and operating the plants in compliance with FERC license requirements, the Company must maintain its plants. If Georgia Power does not reinvest in these plants, the Company may need to surrender its FERC licenses and decommission the plants, at which point the Company could not guarantee that the reservoirs and dam facilities would be preserved and function in a manner consistent with current operations. Given these risks and the benefits associated with the continued operation of its hydro fleet, the Company intends to make appropriate additional investments to ensure the continued operation of the hydro fleet. The total hydro capital budget, including the estimated costs of these investments, is included in the Selected Supporting Information section of Technical Appendix Volume 1.

9.2. CERTIFICATION OF PLANT GOAT ROCK UNITS 9-12

As discussed in ATTACHMENT XXXXXXXXXXXXXXXX., Georgia Power is requesting certification of capacity increases at the Goat Rock hydro facility to correct a flow imbalance in the Chattahoochee River hydro fleet. The Company is replacing turbines at Plant Goat Rock Units 3-6, which will increase the capacity from 5 MW to approximately 9.6 MW for each unit and bring the capacity of the entire Goat Rock hydro facility from approximately 39 MW to approximately 57 MW. As a result of the turbine replacements, Plant Goat Rock Units 3-6 will become Plant Goat Rock Units 9-12. Plant Goat Rock, which is one plant within the Chattahoochee River hydro fleet, impounds the 965-acre Goat Rock Lake and has over 25 miles of shoreline with 45 residential and commercial leases. During drought conditions, Plant Goat Rock is operated in conjunction with the other hydro plants along the Chattahoochee to help support minimum flows downstream for municipal and industrial users.

9.3. DECERTIFICATION OF PLANT ESTATOAH UNIT 1, PLANT LANGDALE UNITS 5-6, AND PLANT RIVERVIEW UNITS 1-2

Georgia Power is also requesting decertification of Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2. Plant Estatoah is located in Dillard, GA, while Plants Langdale and Riverview are located on the Chattahoochee River approximately 30 miles upstream of Columbus, Georgia. These are non-peaking, run of the river hydro plants that provide little capacity. Their reservoirs are very small and have no municipal water intakes.



Plants Langdale and Riverview have FERC licenses with minimal requirements. Plant Estatoah was never connected to the bulk electric system and therefore was not under FERC jurisdiction.

Langdale and Riverview's FERC licenses expire on December 31, 2023. The licenses must be renewed through relicensing or surrendered through FERC proceedings, and FERC required notice of intent to either relicense or surrender by December 31, 2018. Natural resource agencies are in favor of surrender and removing the dams at these facilities to restore riverine habitat for aquatic species of interest. This, coupled with the low capacity of these small hydro plants, weighs in favor of proposing license surrender and dam removal. Therefore, Georgia Power filed on December 18, 2018 to surrender the Langdale and Riverview FERC licenses and is proposing to remove the dams. Removal costs at Langdale and Riverview may be reduced with potential funding partnerships with agencies, although the availability and extent of the funding is unknown at this time.

9.4. RELICENSING SCHEDULE

The following section highlights recent and upcoming relicensing proceedings for various Georgia Power hydro plants that will be ongoing over the next twenty years.

Wallace Dam

License Expires 05/31/2020

Preparation for the relicensing process began internally in 2013. On February 18, 2015, Georgia Power filed a Notice of Intent to relicense the project with FERC. Consultation with stakeholders continued until May 2018, when Georgia Power filed the license application with FERC. FERC will issue a new license by June 2020 that will likely require Georgia Power to provide environmental, recreation and other project enhancements during the new license term. Beginning in 2020, any post-license enhancements required by the new FERC license will be implemented. These enhancements likely will include an in-reservoir pure oxygen aeration injection system to improve dissolved oxygen in the plant discharge, an overhaul of existing recreation facilities, the addition of new bank fishing access areas for the public, and acquisition of lands within the FERC project boundary.

Lloyd Shoals Projects

License Expires 12/31/2023



The Lloyd Shoals relicense process started internally in 2017. A Notice of Intent to relicense the project was filed with FERC on July 3, 2018.

Langdale and Riverview Projects

Licenses Expire 12/31/2023

Georgia Power filed a Notice to Surrender these projects on December 18, 2018.

Rocky Mountain Pumped Storage Project (co-owned and jointly licensed with Oglethorpe Power)

License Expires 12/31/2026

A Notice of Intent to relicense the project must be filed with FERC prior to January 1, 2022. Oglethorpe Power is leading the relicensing effort.

Middle Chattahoochee Project

License Expires 12/31/2034

The external relicense process is scheduled to begin in 2029. A Notice of Intent to relicense the project must be filed with FERC prior to January 1, 2030.

Sinclair Project

License Expires 4/30/2036

The external relicense process is scheduled to begin in 2030. A Notice of Intent to relicense the project must be filed with FERC prior to May 1, 2031.

North Georgia Project (includes Burton, Nacoochee, TERRORA, Tallulah, Tugalo, Yonah)

License Expires 9/30/2036

The external relicense process is scheduled to begin in 2030. A Notice of Intent to relicense the project must be filed with FERC prior to September 1, 2031.



Bartletts Ferry Project

License Expires 11/30/2044

The external relicense process is scheduled to begin in 2038. A Notice of Intent to relicense the project must be filed with FERC prior to December 21, 2039.

9.5. REQUIREMENTS AND RISKS TO RELICENSING

During relicensing, FERC may impose additional license conditions on Georgia Power based on input from federal and state environmental and other resources agencies, non-governmental organizations, and other stakeholders. Outside of the FERC relicensing proceeding, FERC may require additional license conditions during a license term, including in some instances, requirements imposed by federal and state agencies. These requirements may result in loss of capacity and/or generation due to increased minimum flows, seasonal limits on generation, increased water withdrawals, limits on reservoir fluctuations, or dam removal. Additionally, reductions in peaking capability, ancillary services (e.g., voltage control), and operational flexibility could arise due to imposed ramping rates or modifications to current operational regimes. Finally, additional license requirements could come in the form of increased capital investment such as installation of facilities and equipment for environmental purposes (e.g., dissolved oxygen or fish passage facilities), installation and enhancement of recreational facilities, shoreline changes, habitat enhancements, monitoring and surveillance of environmental parameters, or replacement of capacity.



CHAPTER 10. SUPPLY-SIDE STRATEGY

The Company continues to invest in the generation fleet to ensure reliable and affordable electric service to customers. The 2019 IRP supply-side strategy reflects the Company's previous resource commitments, procurement of competitive renewable resources, proposals to investigate the viability of storage technology, investment in hydro-powered resources, and risk mitigation strategies for large coal-fired plants. A complete list of Georgia Power's existing and committed units is contained in the Resource Ledger in Technical Appendix Volume 2.

10.1. PREVIOUS RESOURCE COMMITMENTS

The supply-side plan reflects previous resource decisions and actions resulting from the 2016 IRP, including the retirements of Plant Mitchell Units 3, 4A, and 4B, Plant Kraft Unit 1 CT, and the sale of the Company's ownership in the Intercession City CT. The plan also includes: military, university, and Community Solar projects approved in the 2016 IRP Order; capacity procured and planned under the Company's REDI Program; and proxy biomass QFs.

Additionally, the 2019 IRP reflects the November 2021 and November 2022 target in-service dates for Plant Vogtle Units 3-4, respectively, as approved by the Commission in the 17th VCM Order filed January 11, 2018. Since the 2016 IRP, significant progress has been made at Plant Vogtle Units 3-4, as described in the semi-annual VCM report filings in Docket No. 29849.

10.2. DECERTIFICATION OF RESOURCES

The results of the economic analysis for Plant Hammond Units 1-4 and Plant McIntosh Unit 1 show that it is not economical to invest in these plants to allow for continued operations. The combination of forecasted low gas prices, modest load growth, and continued additional environmental compliance costs create economic challenges for these plants. Both sites require investment in additional environmental controls to comply with federal and state rules and regulations. These costs are required in addition to traditional retrofit capital and O&M costs.

In accordance with the decision in the 2016 IRP, the Company has continued to significantly reduce spending on both Hammond Units 1-4 and McIntosh Unit 1. Additionally, as outlined in the decertification application, retirement of these units does not drive the need for new transmission projects, nor does it impact the Company's ability to maintain a sufficient reserve margin through 2028. Therefore, due to the combination of these factors, the supply-side plan



reflects the retirement of these resources. It should be noted that even though the retirement of Plant Hammond Units 1-4 and Plant McIntosh Unit 1 does not impact the ability to maintain a sufficient reserve margin, these units have aided the resiliency and reliability of the System since the 2016 IRP. Details regarding the assumptions, compliance strategies, and economic analyses for Plant Hammond Units 1-4 and Plant McIntosh Unit 1 are contained in the ECS and Unit Retirement Study within Technical Appendix Volume 2.

The Company also analyzed the economics for continued operation at three small hydro plants. The results of this analysis indicate it is not economical to continue investment in Plant Estatoah Unit 1, Plant Langdale Units 5-6, or Plant Riverview Units 1-2. As discussed in CHAPTER 9., these resources do not have significant impacts on the local communities, and natural resource agencies are supportive of retirement. Therefore, the supply-side plan reflects the retirement of these hydro resources. Economic analyses for these units are contained in the Unit Retirement Study within Technical Appendix Volume 2.

10.3. CERTIFICATION OF ADDITIONAL CAPACITY

The Company is proposing to bring 25 MW of Plant Scherer Unit 3 wholesale capacity into retail service under the provisions of the Commission's July 30, 2008 Order in Docket No. 26550. Plant Scherer is the most economical coal plant in the Georgia Power fleet and continues to benefit customers. As economic pressure persists for older coal units in Georgia, acquiring additional capacity associated with Plant Scherer is important to the Company's ability to provide generation diversity while supporting reliable and resilient operations. This certification request is further discussed in CHAPTER 11.. The supply-side strategy reflects the 25 MW of Plant Scherer Unit 3 as serving retail customers.

Plant Goat Rock requires additional investment to maintain reliable operation. The Company is taking advantage of this opportunity to increase the capacity of this hydro facility. As discussed in CHAPTER 9., this increase will help correct water flow imbalances on the Chattahoochee River and improve the Company's ability to optimize water flow of other hydro resources on the river. The supply-side strategy reflects this increase in capacity at Plant Goat Rock.

10.4. ENVIRONMENTAL COMPLIANCE STRATEGY

Georgia Power has a long history of demonstrating environmental stewardship while meeting the energy needs of customers. Complying with federal and state environmental requirements is



a fundamental element of the Company's longstanding commitment to meet these energy needs. Consistent with the Company's effort to supply clean, safe, reliable, and affordable energy, the ECS describes the comprehensive strategy designed to comply with environmental laws and regulations through the implementation of cost-effective and commercially available environmental control applications.

Through making effective investments that are consistent with the best interests of its customers, Georgia Power has invested over \$5.5 billion in environmental controls. In doing so, it has achieved nitrogen oxide ("NO_x") and sulfur dioxide ("SO₂") emission reductions of 93 and 99 percent, respectively, since 1990 and mercury emission reductions of approximately 95 percent since 2005. Additionally, Georgia Power has reduced CO₂ emissions by more than 50 percent since 2007.

The 2019 ECS reflects the Company's strategy to comply with numerous federal and state requirements, including the ELG rule and both the federal and state CCR rules for the Company's fossil-fuel-fired plants. The ELG and CCR rules require the installation of additional environmental controls for wastewater treatment and dry ash handling. These rules also require closure of ash ponds and add additional requirements for CCR landfills. In light of these requirements, Georgia Power is permanently closing 29 ash ponds at its coal-fired power plants. In doing so, Georgia Power will incorporate site-specific closure strategies that effectively balance multiple factors such as pond size, location, and geology, as well as the amount of material at each site. Moreover, advanced engineering methods will be designed to enhance the protection of groundwater. Such methods may include slurry walls, in-situ solidification/stabilization and/or cover system enhancements. Closure of the ash ponds is regulated under both CCR rules (state and federal) and will be required and overseen by Georgia EPD through its issuing of site-specific permits that mandate compliance actions for each ash pond and landfill. Expenditures associated with the closure of CCR ash ponds and landfills under the CCR rule are reflected in the CCR ARO tables in the Selected Supporting Information section of Technical Appendix Volume 1.

The ECS also discusses recent developments in CO₂ regulations. On August 21, 2018, the US Environmental Protection Agency ("EPA") proposed the Affordable Clean Energy ("ACE") rule, which will establish and revise guidelines to be used by states in developing their own plans for regulating greenhouse gas emissions from existing coal-fired power plants. To date, the rule has not been finalized. As such, state plans have yet to be developed and implemented, and



potential legal proceedings related to the rule and state plans have yet to occur. Consequently, Georgia Power has not initiated compliance plans for the ACE rule and is, therefore, not including such compliance plans in this IRP. However, as discussed in CHAPTER 4., the Company considers the impacts of pending and future carbon legislation or regulation in the planning scenarios and unit evaluations. Based upon information currently available, the Company believes any future analysis related to the ACE rule would reflect that the implications of the rule remain within the range considered in the Company's existing planning scenarios.

The Company anticipates that the ECCR tariff will need to be updated in the 2019 base rate case to appropriately reflect the incremental costs of environmental compliance. However, consistent with past practice the IRP is the appropriate proceeding for the Commission to approve the Company's environmental compliance strategies and related costs. The incremental capital and O&M environmental compliance costs for which the Company seeks approval are more specifically described in the Selected Supporting Information section of Technical Appendix Volume 1.

10.5. FUTURE UNCERTAINTY

The Company has performed an in-depth economic analysis of certain of its fossil-fired generating units to determine which plants provide economic benefit to customers. To ensure reliable operations, no additional coal units can be retired at this time beyond Plant Hammond Units 1-4 and Plant McIntosh Unit 1. While the Company recognizes the economic challenges facing Plant Bowen Units 1-2 in certain scenarios, the continued operation of these units in the near term is imperative to maintaining reliability. These units provide benefits to the transmission system, reduce exposure to potential generation shortfalls, and improve resiliency of the System. Unlike Plant Hammond Units 1-4 and Plant McIntosh Unit 1, the Company could not retire Plant Bowen Units 1-2 without identifying and procuring new capacity upon retirement. Additionally, in higher gas price scenarios, Plant Bowen Units 1-2 remain economically competitive, demonstrating the benefits of preserving the option to maintain coal generation. Therefore, this IRP does not propose the retirement of Plant Bowen Units 1-2 as these units continue to provide numerous benefits to customers and are needed to maintain reliable operations.

However, in recognition of the economic challenges facing Plant Bowen Units 1-2 in certain scenarios, the Company is taking steps to minimize future investment in these units. While



some investment is required due to maintenance and environmental mandates, the Company intends to defer major retrofit projects and optimize implementation of projects necessary to manage the near-term availability of these units. These steps mitigate the risk related to significant capital expenditures but increase the potential for unplanned outages and associated reliability impacts.

For the transmission system to accommodate potential future retirements beyond Plant Hammond Units 1-4 and Plant McIntosh Unit 1, the Company must make transmission infrastructure investments beyond what is identified in the base 10-year transmission plan in Technical Appendix Volume 3, which assumes continued operation of large generating units. These transmission projects are reflected in the Company's unit retirement study analyses and must be completed before potential future retirements occur. Therefore, the Company plans to initiate the activities necessary to ensure the timely completion of these projects, or equivalent solutions. These steps enable decision-making flexibility in the event future retirements are appropriate.

10.6. CAPACITY REQUESTS FOR PROPOSALS

Georgia Power is projected to have sufficient resources to meet customers' needs in the near term given the resource decisions approved by the Commission in the 2016 IRP Order and previous proceedings. However, the Company is projected to have a capacity need in 2028 based on projected load growth, expiration of PPAs, and the decertifications requested in this IRP.

As previously discussed, in light of the economic challenges facing Plant Bowen Units 1-2, the Company intends to defer major investments in these units to the extent practicable. However, indefinite deferral of investments or otherwise limiting capital spend will likely cause Plant Bowen Units 1-2 to become unavailable starting with the latest applicability date of the ELG rule, which is currently set for December 2023. Consequently, to maintain reliability and fill a capacity need in the potential absence of these units, the Company intends to issue a capacity-based RFP, seeking resources that can provide capacity beginning in 2022 or 2023, ahead of the latest applicability date for the ELG rule. In the event the market cannot provide adequate and economic capacity during the 2022-2023 RFP, the Company intends to preserve the ability to continue operating Plant Bowen Units 1-2.



Beyond Plant Bowen Units 1-2, in the event future retirement of any remaining steam units is in the best interests of customers, the Company would need to identify new capacity resources. To prepare for this possibility and preserve decision-making flexibility, the Company is requesting approval to issue a second capacity-based RFP which can provide capacity beginning in the 2026-2028 timeframe, ahead of the Company's currently projected capacity need. The 2026-2028 RFP provides the Company flexibility to complete necessary transmission improvements and allow for a five-to-seven-year process for the evaluation of bids and construction of a new capacity resource by the Company or market participants, should new construction be in the best interests of customers.

10.7. BLACKSTART RESOURCES

For System restoration purposes, certain generating units are designated as "Blackstart Resources." Blackstart Resources are defined by NERC reliability standards as "a generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for Real and Reactive Power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan."⁵ A review and assessment of Blackstart Resources and the Company's Transmission Operator system restoration plan is conducted in conjunction with unit retirement studies. System restoration plans are updated no less than annually or as required due to changes in the future mix of generating assets.

10.8. NEW RENEWABLES

The Company's supply-side strategy for renewables seeks to procure up to 950 MW of utility-scale renewable resources through the CRSP program. Additionally, the Company is proposing to procure up to 50 MW of renewable DG resources. These procurements will continue to leverage a competitive bidding process as the Company builds on the success of the previous REDI program. These plans are discussed in greater detail in CHAPTER 8..

10.9. BATTERY ENERGY STORAGE SYSTEMS

Energy storage deployments are increasing across the United States and have the potential to make positive contributions to the electric system. Due to advancements in technical

⁵ Glossary of Terms Used in NERC Reliability Standards - https://www.nerc.com/files/glossary_of_terms.pdf



performance and continuous reductions in cost, Battery Energy Storage Systems (“BESS”) can be a solution to address a wide range of challenges related to the generation and delivery of electric power across the grid.

Capabilities and Applications

BESS can bring value to customers by performing the following functions:

Dispatch Operations Optimization and System Resiliency

Advanced battery technologies have the potential to provide operational flexibility due to the capability for sub-second response. As such, BESS can provide essential reliability and dispatch operations services to the grid, such as frequency response support, quick-start, and fast-acting ramp capability. Opportunities exist to validate the effectiveness of battery storage for short response and faster reaction time applications in comparison to traditional generation resources. Additionally, validation of the daily and seasonal discharge schedule will allow operations to fully optimize the dispatch of generation assets.

Renewables Integration

BESS offer the flexibility needed to handle the unexpected moment to moment variations caused by intermittent renewable resources, the rapid change in ramping requirements due to the changing availability of the renewable resources, and potential “bottom-out” conditions caused by must-take renewable energy on low-load days to ensure grid reliability. New battery energy storage facilities may be viable resources for dealing with these challenges over time.

Non-dispatchable, renewable resources are an integral part of Georgia Power’s generation mix. As such, it may become beneficial to shift the energy from these resources, such as solar, to more valuable hours of the day. BESS provide opportunities to optimize scheduling, economic valuation, and dispatch capabilities when peak generation is shifted from renewable resources such as solar for later use when the demand is high.



Transmission and Distribution (“T&D”)

BESS may have the potential to defer traditional wires investments related to load growth and congestion thus acting as non-wires alternatives (“NWAs”). Additionally, BESS may have the ability to provide voltage support to the grid.

Utility-Scale Storage

Unlike traditional generation resources, BESS have the capability of both increasing the grid’s total load during low load periods (charging) and serving load during high load periods (discharging), thereby flattening the effective system load shape. BESS can also serve as an alternative to the traditional peaking resource and provide System operating reserves to serve load reliably.

Deployment Strategy

The Company proposes to develop a total of 50 MW of energy storage capacity for this IRP to evaluate the technical and economic performance relative to expectations, including the ability to use BESS for multiple applications. The two proposed project configurations are as follows:

- Independently sited battery energy storage system(s)
- Battery energy storage system(s) to be located at or near solar facility(s)

These battery energy storage deployments will provide the ability to:

- Validate operational and performance capability in a real-time environment;
- Examine integration of storage technology, operating assumptions and new energy storage development costs as a part of new build resources;
- Fully evaluate the benefits and costs of combinations of resources, such as solar plus battery storage; and
- Obtain operational performance analyses to inform and refine BESS operation and preventive maintenance practices, including identification of technology and component specific degradation rates and failure mechanisms.

The projected costs for these energy storage projects are contained in Selected Supporting Information section of Technical Appendix Volume 1.



The proposed BESS may enhance the System's ability to meet demand and allow the Company to validate the operational and performance metrics of a quick response unit. Also, as previously discussed, the 2019 IRP reflects the Company's plan to add 1,000 MW of new renewable resources. These resources will complement the approximately 2,500 MW of planned and committed solar resources.⁶ Renewable resources are intermittent resources inherently dependent on weather conditions. Energy storage could prove to be a sound solution to address a wide range of challenges in the management of a diverse electric generating fleet, such as dispatch operations optimization, compliance with current and future NERC standards, renewables peak energy shifting, firming, and integration.

While each of these benefits can be impactful, unless they are optimized and appropriately coordinated with grid operations, it is unlikely they will deliver the benefits in the manner expected. Therefore, the Company seeks approval to acquire, own, and implement these battery energy storage projects to advance its understanding of storage capabilities while providing real-world operating experience to better integrate future storage projects. The Company's approach will provide the opportunity to test several of these value streams simultaneously and gain valuable insight into how to maximize the value of storage.

10.10. DISTRIBUTED ENERGY RESOURCES

Technologies associated with DERs are experiencing cost declines while presenting new opportunities and challenges for future deployment and management on the distribution grid. Currently, the following resource types are commonly recognized forms of DERs: solar; battery storage; electric vehicles; small combined heat and power units; microturbines; internal combustion generators; flywheels; interruptible loads; critical pricing programs; demand response and energy efficiency programs; and Volt/VAR applications. Based on the variety of potential DER applications, the Company is preparing for greater integration of DERs by researching and evaluating the development of a DERMS platform while investigating DERs as NWAs.

⁶ Georgia Power purchases only the null energy output from some renewable generating facilities that have contracted to sell energy from their facilities to Georgia Power. The ownership of the associated RECs is specified in each respective PPA and the party that owns the RECs retains the right to use the RECs. Georgia Power does not report emission reductions from the null energy purchased through PPAs that do not bundle the RECs for sale to Georgia Power.



Distributed Energy Resource Management System

Historically, the Company has installed hardware and software to deliver safe and reliable service on the distribution grid for one-way power flow by utilizing supervisory control and data acquisition (“SCADA”) systems. SCADA systems allow the Company to automatically and remotely isolate and restore electric service. Advanced distribution management systems (“ADMS”) enhance base SCADA systems by providing additional insight to grid dynamics including those brought about by DERs. ADMS platforms provide enhanced reliability and grid analytics that allow ADMS to serve as the foundation for new grid integration in the future. The complexity of the grid will continue to increase with the integration of DERs that create new supply-side resources operating in parallel with existing central-station generation resources. To effectively integrate these resources, utilities must be capable of remotely leveraging the advanced features of DERs. Therefore, continued investment in specialized grid hardware and software, known as DERMS, is required to effectively integrate increased deployment of resources and technology. Specifically, more granular insight into the distribution system allows for end-to-end monitoring, operation, and control of DERs necessary to effectively ensure safe, reliable, and affordable service to customers. DERMS is an emerging platform in the industry that is in the beginning stages of development and deployment. There are limitations in current DERMS technologies that may impede the immediate integration with existing systems including SCADA, fleet operations, and customer information systems.

During the next three years, the Company will continue to evaluate the design and development of a DERMS consisting of an end-to-end software platform and hardware integration for purposes of effective DER integration. The scope of the DERMS evaluation will include consulting and research to review market-ready DER capabilities and develop requirements for integration. This evaluation is the beginning of a process to implement a market-ready, technology-indifferent hardware and software solution to integrate various DERs to centrally monitor and optimize the distribution system in real-time. During the evaluation process, the Company will test proven technologies in demonstration projects to capture the capabilities of DERMS for future system wide integration. The results of the evaluation will serve as the foundation to our future DERMS decisions and strategy.



Non-Wires Alternatives

NWAs are part of a growing trend toward increased T&D grid flexibility, with smaller localized projects being contemplated as alternatives to generally larger and more centralized projects intended to either add or expand grid infrastructure capabilities. Implementing non-traditional solutions for T&D system constraints may allow for the avoidance or deferral of traditional solutions. Typically, these non-traditional solutions utilize one or more DERs in a specific location to address changing load requirements and/or solve voltage, thermal, power quality and other electrical system constraints that would have required expansion or upgrades.

Careful consideration for these alternatives must be made to determine if NWAs provide equivalent or increased benefits when compared to traditional T&D solutions. For example, an NWA, such as battery energy storage, may solve a distribution line overload for 60% of the time when the line is overloaded, while traditional reconductoring would solve the problem 100% of the time and provide extra capacity for potential load growth. Also, total life cycle and ownership costs, including maintenance and replacement costs, must be incorporated when comparing non-wires and wires solutions. The Company is cataloging the costs, feasibility, and use cases for these options and will consider them where more traditional solutions are not practical or economical.

The Company currently uses the Transmission Planning Principles listed in Technical Appendix Volume 3 as a guideline to determine T&D substation needs and projects to address those needs in a reliable and least cost fashion. These needs can arise from several issues, including, but not limited to, load growth, electrical flow changes from unit retirements or additions, and existing equipment life cycle completions. The Company routinely evaluates T&D solutions, including NWAs, to address these needs. As the Company continues to update cost and application information associated with DERs, those resources will be considered along with traditional wires solutions as well as other NWAs. Specifically, DERs as NWAs will be evaluated based on their ability to address T&D needs, the necessary lead-time for procurement and installation, and a financial analysis over the life of the asset. The Company will select the best overall solution that complies with NERC Reliability Standards and maintains System reliability.



CHAPTER 11. WHOLESALE GENERATION

The Commission's July 30, 2008 Order in Docket No. 26550 obligates Georgia Power to offer certain wholesale resource blocks to the retail jurisdiction on then-current wholesale market terms. Previous wholesale capacity blocks offered under this arrangement have been accepted by the Commission. As additional wholesale contracts expire, the Company evaluates when to offer wholesale capacity blocks to the retail jurisdiction.

Approximately 25 MW of Plant Scherer Unit 3 capacity is currently under contract to Flint EMC through December 31, 2019. Georgia Power is offering the 25 MW of capacity to the retail jurisdiction to serve retail customers when the capacity becomes available on January 1, 2020.

In prior wholesale capacity offers, the Company has utilized, and the Commission has approved, the application of a Market Differential Adjustment ("MDA") to meet the requirement that the transaction be offered at then-current wholesale market terms. The MDA represents the difference between the market price and the levelized revenue requirement of the net asset over its remaining useful life, expressed on a dollar per kilowatt-month basis. Since the July 2008 Order has been in place, the Company has made multiple wholesale offerings to the retail jurisdiction, resulting in a range of MDAs, depending on the generation resource involved and the wholesale conditions present at the time. The Company recognizes the importance of maintaining fuel diversity, and, thus, proposes to offer the Plant Scherer capacity to the retail jurisdiction, under the same MDA construct utilized previously, effective when it becomes available with the expiration of the Flint EMC contract at the end of this calendar year.

If the Commission accepts the Company's offer of approximately 25 MW of Plant Scherer Unit 3 to the retail jurisdiction, the Company requests that the capacity also be granted certification in this IRP. Given the loss of significant coal capacity in the past several years, the request to decertify additional coal capacity at Plants Hammond and McIntosh in this IRP, and the uncertain future of Plant Bowen Units 1-2, the Company believes it is appropriate to take this opportunity to acquire additional capacity from the Company's most economical coal resource, Plant Scherer.

Additional information on the offer can be found in the Selected Supporting Information section of Technical Appendix Volume 1, with the formal certification request included in the 2019 Certification Application in ATTACHMENT UUUUUUUUUUUUU..



CHAPTER 12. TRANSMISSION

This IRP includes the Company's ten-year transmission plan, which identifies the transmission improvements needed to maintain a strong and reliable transmission system, based upon current planning assumptions. Along with the ten-year plan, Georgia Power has included a comprehensive and detailed bulk transmission plan of the Georgia ITS summarizing studies, project lists, processes, data files and other information as required by the amended Rules adopted by the Commission in Docket No. 25981.

12.1. TRANSMISSION PLANNING PRINCIPLES

The purpose of the transmission planning principles is to provide an overview of the standards and criteria that are used for transmission expansion and upgrade proposals. These principles are designed to help ensure the coordinated development of a reliable, efficient, and economical electric power system for the transmission of electricity for the long-term benefit of the transmission users. These principles also recognize that planning should be proactive to ensure timely system adjustments, upgrades, and expansions. The principles that apply to Georgia Power's transmission planning are as follows:

1. Identify and recommend projects that are consistent with the Guidelines for Planning the ITS and the Guidelines for Planning the Southern Company Electric Transmission System;
2. Identify and recommend projects that are consistent with the NERC Reliability Standards;
3. Minimize costs associated with the transmission system expansion, considering the impact to system reliability;
4. Identify projects with sufficient lead-time to provide for the timely construction of new transmission facilities;
5. Coordinate transmission system plans with the plans developed by Georgia Power's Power Delivery Planning groups;
6. Coordinate transmission system plans with all ITS Participants and other transmission owners to enhance reliability and minimize associated costs;



7. Coordinate future transmission plans with other Georgia Power departments, other ITS Participants, other SCS departments and the regions surrounding the Southeast in the project development and planning processes;
8. Maintain adequate interconnections with neighboring utilities;
9. Communicate with Georgia Power management to ensure proper awareness of the importance of adequate transmission improvements and system expansion;
10. Utilize existing resources (for example, reusing rights of way, implementing voltage conversions, constructing double-circuit lines) where feasible;
11. Minimize transmission losses when cost effective; and
12. Avoid the loss of life to transmission equipment from forced operation at higher loading levels.

These principles provide guidance to Transmission planners and/or planning authorities that are called upon to explore existing issues and any future problems encountered in the transmission planning process.

12.2. TEN-YEAR TRANSMISSION PLAN

Georgia Power is a member of the ITS, which consists of the physical equipment necessary to transmit power from the generating plants and interconnection points to the local area distribution load centers. The ITS consists of electric transmission facilities that are individually owned and maintained by the ITS Participants. Transmission planning embodies investment decisions required to maintain sufficient capacity in the ITS to reliably meet the power needs of the public. Justifications for these decisions are based on technical and economic evaluations of options that may be implemented to meet these needs. Under the ITS Agreements, the ITS Participants are responsible for meeting their full load requirements, including generation, and are responsible for making improvements to their facilities to accommodate transmission improvements required by load growth or system reliability.

Transmission Planning-East (“TP-E”) of SCS and Power Delivery System Performance of Georgia Power, with input from Power Delivery Operations of Georgia Power, are responsible for planning the transmission system for Georgia Power. TP-E develops a planning model of the



transmission system for each year for ten years into the future. This planning model is used to identify transmission problems and to evaluate alternative solutions to those problems.

All Transmission Planning information is provided in Technical Appendix Volume 3 per the Commission's 2007 IRP Order and the amended rules adopted by the Commission in Docket No. 25981. Additional Transmission Planning information required per Docket No. 31081 is available in Technical Appendix Volume 3.



CHAPTER 13. EMERGING RESILIENCE NEEDS

As society develops and becomes increasingly reliant on electric energy, the Company remains committed to maintaining a robust and resilient electric system that is capable of reliably delivering electric energy, even in the face of unexpected events such as natural and man-initiated disruptions. The Company has an excellent track record managing and planning for reliability risk through its reserve margin process, transmission planning analysis, and similar reliability studies, while also demonstrating substantial commitment to infrastructure protection initiatives. As the Company continues to evolve its generation fleet toward a larger share of resources that either have no on-site fuel storage or are intermittent, there is increased fuel transportation risk associated with providing reliable electric service to customers. Additionally, the threat of high-impact events that have low probability, such as physical- and cyber-attacks, continues to grow. Therefore, as customers and the economy become increasingly dependent on electricity, it is all the more important that the Company remain vigilant in its commitment to maintaining a robust and resilient electric system that is capable of delivering clean, safe, reliable, and affordable energy to its customers.

The resilience of the power delivery system can be narrowed to items specifically at the circuit level or more broadly at the bulk power system level. At the circuit level, the Company will continue to address resilience in ways that will cost effectively provide consistent levels of sustained reliability. For example, the Company will continue to focus on implementing self-restoring networks, utilizing advanced control and monitoring technologies, targeted undergrounding of infrastructure, strategic infrastructure segmentation to expedite restoration, implementation of additional feeder ties, and the replacement of aging transformers, lines, and structures.

At the bulk power system level, the Company routinely evaluates various contingencies as part of its Transmission Planning process and proposes projects to mitigate the risks associated with these contingencies. This level of planning meets or exceeds current NERC standards. However, as the Company's generation resource mix continues to change, utilizing less coal and more renewables and gas generation, continued transmission planning considerations must be given to these changing conditions to ensure future reliability and resilience of the bulk power system. This may require additional assessments of contingencies that may affect the IRP. Such assessments should focus on the simultaneous failure of multiple elements of the electricity supply chain such as transmission substations, gas pipelines, communication infrastructure, and



generating stations. In many cases, this level of assessment is beyond current NERC planning standards. As a result, projects which may minimize or eliminate the potential for high-impact outcomes may not be required or proposed. However, when in the best interest of customers, the Company may propose projects to address such scenarios and conditions in accordance with its ITS joint planning process.

Similar to transmission assessments, the Company regularly evaluates generation risks such as outage risk, weather risk, and even fuel transportation risk as demonstrated in its Reserve Margin Study. This study does not focus on other potential long duration, high impact events. Rather the objective of the Company's overall planning process is to maintain reliable and affordable service across a range of possible futures that represent anticipated recurrence of past variations in weather, loads, etc. This planning process has resulted in retirements of over 3,100 MW of coal capacity representing approximately 20% of the Company's 2018 peak load and these retirements were in the best economic interests of our customers. In this IRP, the Company is proposing to retire an additional 982.5 MW of coal capacity at Plants Hammond and McIntosh. These retirements are also in the best economic interests of customers, and do not impact the Company's ability to maintain a sufficient reserve margin. However, these units have been called into action over the past several years and have aided the resilience and reliability of the System since the 2016 IRP, all while under spending limitations. As future coal retirements remain possible, the Company will need to balance the economic benefits of retirement and the ability to take advantage of low-cost gas commodity prices against the potential risk associated with gas fuel supply. Striking the right balance requires consideration of numerous options such as energy storage, inactive reserve, or fuel storage, which may preserve on-site fuel while minimizing spend. These items could prove to be an important resilience consideration with respect to potential future retirement decisions, such as for Plant Bowen Units 1-2.

The Company is **not** requesting specific resilience enhancements in this IRP related to high impact low probability events. However, the growing threat of these risks and the transition of the generating fleet compels the Company to consider these risks and, where appropriate, propose projects for the Commission's consideration.



CHAPTER 14. CONCLUSION & ACTION PLAN

The 2019 IRP reflects the Company's plan to continue to provide clean, safe, reliable, and affordable energy for customers through the continued focus on reliability and resiliency, further actions to transition the resource portfolio, and proactive steps to position the Company to respond to future developments. This IRP details the Company's plan to support future reliability by implementing seasonal planning and developing strategies to identify new capacity resources while making the appropriate reliability-based investments in the transmission system. The Company proposes the procurement of renewable resources through market-based solicitations leveraging the RCB Framework in resource evaluations, the modification and continuation of demand-side programs, investment in flexible hydro-powered resources, BESS projects, and a cost mitigation plan for large coal-fired plants. In addition to the items specifically contained in the conclusion of CHAPTER 1., pending Commission approval where necessary, the Company plans to take the following actions:

- Build, operate, and maintain the necessary generation and power delivery infrastructure to ensure adequate reliability and serve the needs of Georgia;
- Identify, examine, and initiate the activities necessary to ensure timely completion of transmission infrastructure which will ensure reliability in the face of potential future generation retirements;
- Initiate execution of the necessary environmental compliance strategy to comply with government-imposed environmental mandates;
- Continue to provide and assess opportunities to integrate cost-effective resources;
- Utilize the methodologies outlined in the RCB Framework for resource evaluations.



ATTACHMENT A. MAJOR MODELS USED IN THE IRP

ATTACHMENT B. SERVM

ATTACHMENT C. SERVM is an industry-wide accepted generation reliability model used for Resource Adequacy analyses. SERVM is an hourly, chronological model that utilizes Monte Carlo techniques. Random draws from unit historical failure and repair times are used to simulate unplanned outages. The model executes beginning with 1 A.M. on January 1, committing units, tracking available hydro energy, operating pumped storage units, considering weather-appropriate renewable output, making economic and reliability purchases from other entities in the region, calling interruptible load as needed, and, if necessary, curtailing firm load.

ATTACHMENT D. Evaluations are typically performed for multiple weather-years, multiple peak load forecast error assumptions, and multiple different start days for the year, resulting in hundreds of cases evaluated per simulation. Each case itself is processed multiple times using random unit outage draws with each iteration and the results of these iterations averaged together to get a case-specific result. Finally, each case has its own probabilistic weighting and is then averaged together with all cases to obtain a weighted-average, expected result for the whole simulation. The Reserve Margin Study contains the details regarding the number of simulations run to generate the Target Reserve Margin recommendations.

ATTACHMENT E. Useful information provided by SERVM includes (but is not limited to):

- Expected unserved energy – the amount of energy that cannot be served due to generating capacity shortages;
- Loss of load expectation – the number of days per year in which firm load is not served;
- Interruptible load – the number of times that interruptible load is called upon; and
- Production costs – the generation and purchase costs associated with serving load requirements throughout the year.

ATTACHMENT F. SERVM is a major planning tool supporting numerous studies. It is used in: (1) developing the Target Reserve Margin; (2) developing Capacity Worth Factor Tables used for renewable resource valuations, PRICEM, and other capacity value calculations; (3) performing operational reliability studies; and (4) developing incremental capacity equivalent (ICE) factors for demand-side and supply-side resources.



ATTACHMENT G. Econometric Forecasting Models

ATTACHMENT H. Georgia Power's short-term forecasts are produced using econometric forecasting models, which estimate the relationships between economic and demographic variables and energy use. These models use ordinary least squares regression techniques.

ATTACHMENT I. Load Management and Planning: Residential

ATTACHMENT J. The Residential LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the residential sector. This model was developed in 2007 by Applied Energy Group (formerly EnerNOC).

ATTACHMENT K. Load Management and Planning: Commercial

ATTACHMENT L. The Commercial LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the commercial sector. This model was developed in 2007 by Applied Energy Group (formerly EnerNOC).

ATTACHMENT M. Load Management and Planning: Industrial

ATTACHMENT N. The Industrial LoadMAP model is an end-use model that is used to develop a long-term energy forecast of the industrial sector. This model was developed in 2007 by Applied Energy Group (formerly EnerNOC).

ATTACHMENT O. Hourly Peak Demand Model (PDM)

ATTACHMENT P. The PDM is an hourly demand model that produces projections of peak demand using forecasted class energy, historical class load shapes and corresponding weather, and a description of typical (normal) weather. The PDM was developed by Corios.

ATTACHMENT Q. EnerSim

ATTACHMENT R. EnerSim is a building energy simulation model, used to predict hourly energy consumption in buildings based on construction characteristics, insulation, occupancy, orientation, local weather, and other attributes.



ATTACHMENT S. PRICEM

ATTACHMENT T. PRICEM is a spreadsheet-based marginal cost model designed by SCS to predict the change in revenue requirements and other effects attributable to changes in loads and/or revenues. PRICEM takes data from other major models and combines them in a single spreadsheet to provide for quick, yet relatively detailed, evaluations of options. Data inputs are consistent with inputs to Strategist and as such are taken from: (1) revenue requirements streams from Standard Analysis Model ("SAM"); (2) marginal energy cost from AURORA; (3) ICE factors from SERVM; and (4) GTDB cost assumptions.

ATTACHMENT U. PRICEM models the year with 864 load points and uses the peaker method, a technique allowing the total of generating capacity cost and energy cost to be estimated with peaking capacity and marginal energy cost. The peaker method allows for quick screening of many alternatives. Useful information that can be gathered from PRICEM includes:

- RIM – A net present value calculation of the total benefits and total costs over the life of the program; and
- Predictions of the amount of generating capacity needed to maintain System reliability after a change in interruptible or firm loads.

ATTACHMENT V. Strategist and PROVIEW

ATTACHMENT W. PROVIEW is a generation planning optimization module of the Strategist production cost model. It uses dynamic programming techniques to calculate the total capital and operating costs for hundreds of combinations of generating units. It calculates the minimum cost combination of units.

ATTACHMENT X. The useful information that can be gathered from Strategist includes:

- Least cost combination of generating unit additions by year;
- Additional cost of generation expansion plans that are not the least-cost plan; and
- Estimates of fuel use by fuel type.

ATTACHMENT Y. Strategist is the basis of the benchmark plan. Sensitivity analyses performed through Strategist provide information for developing a combination of generating units that will provide a good combination of flexibility, risk reduction, and other



considerations. Strategist is used to integrate the supply-side options and the demand-side programs to produce the IRP. Strategist is also used to evaluate bids received in the competitive bidding process.

ATTACHMENT Z. AURORA

ATTACHMENT AA. AURORA is used to estimate marginal energy costs for use in various models and analyses. AURORA is an hourly model that utilizes Monte-Carlo techniques to randomly simulate unit forced outages.

ATTACHMENT BB. The useful information that can be gathered from AURORA includes:

- Projections of marginal energy cost by hour for 30 years into the future;
- Projections of the SO₂ and NO_x marginal costs of serving an additional block of load; and
- The cost effects of changing the characteristics of individual units, such as changing heat rates, station service requirements, or similar factors.

ATTACHMENT CC. AURORA supplies important data to many studies. It is used or has been used in: (1) developing the Company's annual energy budget; (2) determining the worth of improving existing units; (3) developing the marginal energy cost for use in PRICEM, GenVal, RCB Framework applications, and elsewhere; and (4) developing the SO₂ and NO_x marginal costs for use in PRICEM.

ATTACHMENT DD. SAM (Standard Analysis Model)

ATTACHMENT EE. SAM is a financial program used to convert capital expenditures into annual revenue requirements. It incorporates projections of the costs of capital, tax rates, and depreciation rates.

ATTACHMENT FF. The useful information that can be gathered from SAM includes:

- Annual revenue requirements necessary to earn a return on and return of the investment;
- Net present value of revenue requirements;
- Levelized fixed charge rates; and
- Economic carrying costs.



ATTACHMENT GG. SAM provides key calculations for numerous studies. It is used or has been used in: (1) calculating revenue requirements streams and economic carrying cost rates for PRICEM; and (2) calculating the economic carrying cost rates and net present value of revenue requirements for many studies, including for use in Strategist.

ATTACHMENT HH. GenVal

ATTACHMENT II.

ATTACHMENT JJ. GenVal is a model that is used to project the economic dispatch of a generating unit within the Southern Company fleet of resources. It utilizes hourly marginal costs from AURORA, as well as the operating characteristics of the generating unit to be analyzed. The useful information that can be gathered from GenVal includes the System production cost impacts due to the inclusion of the generating unit within the Southern Company generation fleet.

ATTACHMENT KK.



ATTACHMENT LL. TECHNOLOGY SCREENING

ATTACHMENT MM. Before a technology is considered in the detailed screening, an initial screen is done by Generation Planning and Development with consultation from SCS Research and Development (“SCS R&D”), Environmental Affairs, the Technical Services division of Engineering and Construction Services and other functions as appropriate to determine if further evaluation is merited. Table B-1 lists the technologies that begin the initial screening process.

ATTACHMENT NN. *Table B-1: Preliminary Screening Technologies (summary)*

ATTACHMENT OO. COAL-FUELED	ATTACHMENT PP. NUCLEAR
ATTACHMENT QQ. Subcritical Pulverized Coal	ATTACHMENT RR. Advanced LWR Evolutionary
ATTACHMENT SS. Supercritical Pulverized Coal	ATTACHMENT TT. Advanced LWR Passive
ATTACHMENT UU. Ultrasupercritical Pulverized Coal	ATTACHMENT VV. Advanced LWR Modular
ATTACHMENT WW. Advanced Ultrasupercritical Pulverized Coal	ATTACHMENT XX. Generation IV
ATTACHMENT YY. Atmospheric Fluidized Bed Combustion	ATTACHMENT ZZ. Small Modular Reactor
ATTACHMENT AAA. Oxygen-Blown IGCC	ATTACHMENT BBB.
ATTACHMENT CCC. Air-Blown IGCC	ATTACHMENT DDD. RENEWABLES
ATTACHMENT EEE. Non-Integrated Coal Gasification CC	ATTACHMENT FFF. Solar Thermal Parabolic Trough
ATTACHMENT GGG. Integrated Gasification Fuel Cell CC	ATTACHMENT HHH. Solar PV
ATTACHMENT III. Magnetohydrodynamic S	ATTACHMENT JJJ. Wind Power
ATTACHMENT KKK.	ATTACHMENT LLL. Tall Tower Large Rotor Wind Power
ATTACHMENT MMM. LIQUID/GAS FUELED	ATTACHMENT NNN. Offshore Wind Power
ATTACHMENT OOO. CT (Conventional/ Advanced)	ATTACHMENT PPP. Municipal Solid Waste
ATTACHMENT QQQ. CC (Conventional/ Advanced)	ATTACHMENT RRR. Dedicated Biomass
ATTACHMENT SSS. Phosphoric Acid Fuel Cells	ATTACHMENT TTT. Co-fired Biomass or Wood Waste
ATTACHMENT UUU. MCFC & SOFC	ATTACHMENT VVV. Landfill gas
ATTACHMENT WWW. Fuel Cell CC	ATTACHMENT XXX. Geothermal
ATTACHMENT YYY. Reciprocating Engine	ATTACHMENT ZZZ. Solar Stirling Dish
ATTACHMENT AAAA. Microturbines	ATTACHMENT BBBB. Solar Central



	Receiver Technology
ATTACHMENT CCCC.	ATTACHMENT DDDD. Compact Linear Fresnel Reflector
ATTACHMENT EEEE. ENERGY STORAGE	ATTACHMENT FFFF. Ocean Energy and Hydrokinetic Generation
ATTACHMENT GGGG. Pumped Storage Hydro	ATTACHMENT HHHH. Ocean Thermal Generation
ATTACHMENT IIII. Underground Pumped Storage Hydro	ATTACHMENT JJJJ. Direct-fired Supercritical CO ₂ cycle
ATTACHMENT KKKK. Compressed Air Energy Storage – Gen I	ATTACHMENT LLLL.
ATTACHMENT MMMM. Compressed Air Energy Storage – Gen II	ATTACHMENT NNNN.
ATTACHMENT OOOO. Advanced Lead/Acid Battery	ATTACHMENT PPPP.
ATTACHMENT QQQQ. Flow Batteries	ATTACHMENT RRRR.
ATTACHMENT SSSS. Lithium-Ion based Batteries	ATTACHMENT TTTT.
ATTACHMENT UUUU. Flywheel Energy Storage	ATTACHMENT VVVV.

ATTACHMENT WWWW.



ATTACHMENT XXXX. Table B-2 lists the technologies that were evaluated in the initial screening process along with a summary of why they were or were not retained for further analysis.

ATTACHMENT YYYY. *Table B-2: Preliminary Screening Results (detailed)*

ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT CCCC. 1. Subcritical Pulverized Coal (Conventional Pulverized Coal)	ATTACHMENT DDDDD. This technology is mature with a large number of units on the System. New units would include the latest emission control systems to ensure compliance with all applicable environmental regulations and permit requirements.	ATTACHMENT EEEE. NOT RETAINED for further screening at this time due to economic reasons, current environmental requirements for new deployments, and future environmental uncertainty.
ATTACHMENT FFFF. 2. Supercritical Pulverized Coal	ATTACHMENT GGGG. This technology is mature with several units on the System. Environmental performance would be similar to subcritical pulverized coal.	ATTACHMENT HHHH. NOT RETAINED for further screening at this time due to economic reasons, current environmental requirements for new deployments, and future environmental uncertainty.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT IIII. 3. Ultrasupercritical Pulverized Coal ("USC")	<p>ATTACHMENT JJJJJ. This technology involves the evolution of coal-fueled generation to produce slightly higher steam pressures and temperatures to attain higher thermal efficiency. It also includes design for flexible operation, including the maintenance of higher efficiencies at partial loads. Many of these advanced features will gradually be incorporated into new base load coal-fueled capacity as they are made available through US and international research efforts. The environmental performance would be similar to subcritical pulverized coal. Material capabilities limit the practical design of this unit, though currently there are operating designs that exceed supercritical limits (main steam conditions around 3600psia and 1100F).</p>	<p>ATTACHMENT KKKKK. NOT RETAINED for further screening at this time due to economic reasons, current environmental requirements for new deployments, and future environmental uncertainty.</p>
ATTACHMENT LLLL. 4. Advanced Ultrasupercritical Pulverized Coal ("AUSC")	<p>ATTACHMENT MMMMM. This technology represents the targeted design of current US and international AUSC research and embodies coal-fueled generation to steam conditions higher than that achieved by existing ultrasupercritical pulverized coal technology for even higher thermal efficiency (steam conditions approaching 5000psia and 1400F). The environmental performance would be similar to, though slightly better than, subcritical or supercritical pulverized coal due to efficiency gains. This technology is nearing demonstration phases but requires more materials development to be completed.</p>	<p>ATTACHMENT NNNNN. NOT RETAINED for further screening at this time due to current level of development as well as current environmental requirements for new deployments and future environmental uncertainty.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT OOOOO. 5. Atmospheric Fluidized Bed Combustion ("AFBC")	<p>ATTACHMENT PPPPP. AFBC technologies have the potential for sulfur removal without add-on flue gas scrubbers. AFBC is currently better suited to industrial cogeneration and is probably the technology of choice for low grade, high ash coals and are typically limited to 300 MW in size. When combined with future supercritical materials, AFBC economics may improve.</p>	<p>ATTACHMENT QQQQQ. NOT RETAINED for further screening at this time due to economic reasons, current environmental requirements for new deployments, and future environmental uncertainty.</p>
ATTACHMENT RRRRR. 6. Oxygen-Blown Integrated Gasification CC ("IGCC")	<p>ATTACHMENT SSSSS. This concept has potential for modularity, staged construction and improved efficiency and environmental performance over pulverized coal-firing. Capital cost is an important concern of the technology, and the use of advanced turbines is necessary for further efficiency improvement. Southern Company has constructed a power system test facility in conjunction with the US Department of Energy ("DOE") to refine IGCC. Based on most current studies of CO₂ capture for a coal-fueled power plant, IGCC has a cost advantage over pulverized coal because the CO₂ in the gas stream is much more concentrated and at a higher pressure.</p>	<p>ATTACHMENT TTTTT. NOT RETAINED for further screening at his time for economic reasons.</p>
ATTACHMENT UUUUU. 7. Air-Blown IGCC	<p>ATTACHMENT VVVVV. This technology is based on an advanced concept using an air blown transport gasifier and associated combustor. Air blown IGCC offers lower capital costs and higher efficiency compared to oxygen blown IGCC.</p>	<p>ATTACHMENT WWWWW. NOT RETAINED for further screening at his time for economic reasons and cost uncertainty.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT XXXXX. 8. Non-Integrated Coal Gasification CC	<p>ATTACHMENT YYYYY. This concept holds promise for modularity and staged construction. Capital cost is an important concern of the technology and the development of advanced turbines is necessary for further efficiency improvement.</p>	<p>ATTACHMENT ZZZZ. NOT RETAINED for further screening at this time because the integrated version would be more cost-effective and efficient.</p>
ATTACHMENT AAAAAA. 9. Integrated Gasification Fuel Cell CC	<p>ATTACHMENT BBBBB. This is a future concept that depends on the development of advanced fuel cells that would be substituted for CTs in the gasification CC plant to provide high efficiency and extremely low environmental emissions. The commercialization of this concept is still uncertain given its dependence on the development of several advanced technology concepts.</p>	<p>ATTACHMENT CCCCC. NOT RETAINED for further screening at this time due to its low level of development and high degree of uncertainty with cost projections.</p>
ATTACHMENT DDDDDD. 10. Magnetohydrodynamics ("MHD")	<p>ATTACHMENT EEEEEE. MHD's appeal is high efficiency and inherent SO₂, NO_x, and particulate control. The key developmental component is the MHD generator, in which a conducting exhaust gas from the combustion of coal along with seed material is passed through a magnetic field to produce DC electricity. The bottoming cycle is a conventional boiler and steam turbine. However, progress with MHD remains slow to stagnant, and conceptual estimates indicate a very high cost.</p>	<p>ATTACHMENT FFFFF. NOT RETAINED for further screening at this time due to the level of development and cost uncertainties.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT GGGGG. 11. CT (Conventional/ Advanced)	ATTACHMENT HHHHH. Many conventional units exist on the System. The technology is mature, but advanced designs offer even higher turbine inlet temperatures for improved efficiencies. The increasing turbine temperatures will open new reliability questions. CTs can be applied as peaking capacity and in CC plants using natural gas or oil. Advancements are being closely monitored. State-of-the-art combustion NO _x control systems will be incorporated in the designs.	ATTACHMENT IIIII. RETAINED for further screening.
ATTACHMENT JJJJJ. 12. CC (Conventional/Advanced)	ATTACHMENT KKKKK. Units are in operation on the System, and the technology is mature. Future designs using more state-of-the-art CTs will offer better economies (see CTs above). Vendors are now offering new CT designs with increased turbine inlet temperatures for improved CC efficiencies. Each of the major Original Equipment Manufacturers ("OEMs") now offer packaged CC plants, based on advanced gas turbine technology, which offer greater thermal efficiencies and increased operational flexibility compared to conventional units. State-of-the-art NO _x control systems will be incorporated for environmental compliance. A number of advanced CT-based cycles such as the Cascaded Humidified Advanced Turbine ("CHAT"), Humidified Air Injection ("HAI"), and Kalina cycles have the potential for higher thermal efficiencies; however, they have not been commercially demonstrated.	ATTACHMENT LLLLL. RETAINED for further screening.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT MMMMM 13. Phosphoric Acid Fuel Cells ("PAFC")	<p>ATTACHMENT NNNNN. Phosphoric acid electrolyte systems using natural gas are the most mature fuel cell technology and, as such, have the most extensive track record for operational experience. Recent industry activity from Doosan suggests renewed commitment to PAFC technology. This system has shown improvements as well as a reduction in cost. Attractive features include modular construction, low environmental impact, siting flexibility, and high efficiencies at small sizes.</p>	<p>ATTACHMENT OOOOO. RETAINED for further screening.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT PPPPPP. 14. Advanced High Temperature Fuel Cells – Molten Carbonate Fuel Cell (“MCFC”) and Solid Oxide Fuel Cell (“SOFC”)	ATTACHMENT QQQQQ. Fuel cells using molten carbonate or solid oxide electrolyte may be more attractive than the phosphoric acid or polymer electrolyte membrane PEM fuel cell. Since these fuel cells are operated at high temperatures (600-1000°C), the incentives include higher efficiencies; more flexible and simplified fuel processing and use of inexpensive catalysts. Also, by-producing heat at these high temperatures, there are more applications than phosphoric acid systems, such as cogeneration and incorporation of a bottoming cycle. These fuel cells also have potential for use with coal gasification in integrated gasification fuel cell power plants. About 40 units are in the field with capacities ranging from 250 kW to 1 MW. Cost, material selection under high temperature operation, and cell durability remain important issues. Fuel Cell Energy is the only commercializer in the United States for MCFC technology. SOFCs are also moving up on the technology maturity curve, but they are at least a couple years behind the MCFC. However, their long-term cost projection is lower than that of MCFC. Environmental characteristics are expected to be excellent for all fuel cell technologies.	ATTACHMENT RRRRR. RETAINED for further screening.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT SSSSSS 15. Fuel Cell CC ("FCCC")	<p>ATTACHMENT TTTTTT. See Advanced High Temperature Fuel Cells. By-product heat from MCFC or SOFC can be used in bottoming cycles to produce additional power. Siemens demonstrated a pressurized 220 KW SOFC/Micro-tubular ("MT") hybrid in California. and achieved 52% efficiency even though the system was not optimized. FuelCell Energy is also testing an atmospheric MCFC/MT hybrid system. DOE Vision 21 power plant highlights such system at efficiency of 60-70% (80-90% with thermal) with 0 air pollutants and CO₂ (with sequestration) by 2015. The costs from such a system should be at par with market rate.</p>	<p>ATTACHMENT UUUUUU. NOT RETAINED for further screening at this time due to the level of development and cost uncertainties.</p>
ATTACHMENT VVVVVV. 16. Reciprocating Engines	<p>ATTACHMENT WWWWWW. Diesel or gas fired generators could potentially have economics competitive with CTs at very low capacity factors and for dispersed applications. Natural gas fired reciprocating engines are emerging in niche markets around the world, mostly in co-generation applications and backup/standby generation. The current trend is towards larger systems with heat recovery and/or chillers. There are environmental concerns due to relatively high emission rates for certain pollutants when burning diesel fuel.</p>	<p>ATTACHMENT XXXXX. RETAINED for further screening.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT YYYYYY. 17. Microturbines	<p>ATTACHMENT ZZZZZ. Microturbines could potentially have economics competitive with CTs at very low capacity factors and for dispersed applications.</p> <p>ATTACHMENT YYYYYY. Microturbines are emerging in niche markets around the world, mostly in co-generation applications. The current trend is towards larger systems with heat recovery and/or chillers. There are environmental concerns due to relatively high emission rates for certain pollutants when burning diesel fuel.</p>	ATTACHMENT AAAAAAA. RETAINED for further screening.
ATTACHMENT BBBBAA. 18. Pumped Storage Hydro	<p>ATTACHMENT CCCCCC. Pumped hydro energy storage is a large, mature, and commercial utility-scale technology used at many locations in the United States and around the world. Southern Company currently applies this technology on its System. This application has the highest capacity of the energy storage technologies assessed, since its size is limited only by the size of the available upper reservoir. Facilities of this type must deal with environmental issues related to land use and the availability of the water source.</p>	ATTACHMENT DDDDDDD. RETAINED for further screening.
ATTACHMENT EEEEEEE. 19. Underground Pumped Storage Hydro ("UPH")	<p>ATTACHMENT FFFFFFF. Underground pumped storage hydro could avert the environmental and licensing problems of conventional above ground facilities. The high excavation costs and long lead times of UPH significantly reduce its attractiveness. Gravity Power, LLC is also developing an underground pumped hydro based on a large piston/cylinder assembly.</p>	ATTACHMENT GGGGGGG. NOT RETAINED for further screening at this time due to high cost and stage of technology development.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT HHHHHHH. 20. Compressed Air Energy Storage ("CAES") – Gen I (Brayton Cycle Based)	<p>ATTACHMENT IIIIII. CAES plant hardware is commercially available. The first CAES (290 MW) plant was constructed in Germany in 1978. A 100 MW plant was constructed by Alabama Electric Cooperative ("PowerSouth") and began commercial operation in June 1991 and is an integral part of PowerSouth's dispatch. CAES cycles can utilize either above ground (low MW) or below ground (high MW) energy storage options. The potential for large scale energy storage depends on suitable geology for constructing the air storage reservoir. The preferred geology for Southern Company would be salt dome sites in Mississippi and Alabama. CAES has the potential for better local environmental characteristics than pumped hydro.</p>	ATTACHMENT JJJJJJJ. RETAINED for further screening.
ATTACHMENT KKKKKKK. 21. CAES – Gen II (CT Based)	<p>ATTACHMENT LLLLLLL. CAES plant hardware is commercially available. Generation II CAES is a newer design iteration of traditional CAES designs which utilizes a CT and an exhaust heat exchanger to heat the air in the expansion cycle, rather than an integral combustion system. This design appears to be more economically favorable than Generation I. Although subsystems have been proven, this cycle has yet to be demonstrated as an integrated system. CAES cycles can utilize either above ground (low MW) or below ground (high MW) energy storage options. The potential for large scale energy storage depends on suitable geology for constructing the air storage reservoir. The preferred geology for Southern Company would be salt dome sites in Mississippi and Alabama. CAES has the potential for better local environmental characteristics than pumped hydro.</p>	ATTACHMENT MMMMMMM. RETAINED for further screening.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT NNNNNNN 22. Advanced Lead/Acid Batteries	<p>ATTACHMENT OOOOOO. Lead/acid technology is mature, but life at elevated operating temperatures with heavy duty cycles is of concern. Advanced batteries are being developed to achieve higher energy and/or power density, higher reliability, lower maintenance and longer life at a cost that can be competitive to conventional lead acid batteries. Potential applications include load management/peak shaving applications to defer the power plant construction for peaking capacity and backup power for T&D substations. Environmental impact on the local area is expected to be very low when the charging source is not considered.</p>	<p>ATTACHMENT PPPPPP. RETAINED for further screening.</p>
ATTACHMENT QQQQQQ. 23. Flow Batteries	<p>ATTACHMENT RRRRRR. Flow batteries have attracted a lot of interest from investors and developers from stationary energy storage. Flow batteries offer the ability to store energy for long periods of time without losing their charge, relative ease in scaling up, and relative high cycle life. Flow batteries can be categorized into different classes, with true redox and hybrid redox further along the commercialization path. Other classes of flow batteries, such as membraneless, organic, metal hydride, and nano-network are in the early R&D stage.</p>	<p>ATTACHMENT SSSSSS. NOT RETAINED for further screening at this time due to stage of technology development.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT TTTTTT. 24. Lithium-Ion based Batteries	<p>ATTACHMENT UUUUUU. Lithium-ion technology is mature based upon the use of the technology in electronics and EVs. Applications of Li-ion batteries for utility scale, stationary applications are quickly emerging with deployments in California leading the way. Advanced lithium chemistries and batteries are being developed to achieve higher energy and/or power density, higher reliability, lower maintenance and longer life, at a cost that can be competitive with other storage approaches. Potential applications include load management/peak shaving applications to defer T&D upgrades, defer power plant construction for peaking capacity and backup power for T&D substations. Environmental impact on the local area is expected to be very low when the charging source is not considered.</p>	<p>ATTACHMENT VVVVVV. RETAINED for further screening.</p>
ATTACHMENT WWWWWWW. 25. Flywheel Energy Storage	<p>ATTACHMENT XXXXXX. Flywheels store mechanical energy, with the amount dependent on the inertia and rotational speed of the flywheel. Southern Company has demonstrated flywheel feasibility in short term ride-through for power quality ("PQ") applications with very good success, but systems for high energy storage applications for peak shaving and/or load leveling are still undeveloped. Acceptable total system costs have been achieved with the PQ units and the ability to integrate the mechanical and power electronic components has been demonstrated. Monitoring of activity in the MW class systems continue and further cost reductions for composite materials, magnetic bearings, and power electronics will improve the chances for future electrical energy storage applications.</p>	<p>ATTACHMENT YYYYYYY. NOT RETAINED for further screening at this time due to high costs and better suitability for dispersed generation applications.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT ZZZZZZ 26. Nuclear Advanced Light Water Reactor ("LWR") – Evolutionary	<p>ATTACHMENT AAAAAAAA. These plants are similar in design to Hatch, Farley and Vogtle but incorporate many evolutionary improvements in areas such as controls, systems, materials, construction techniques, and a streamlined regulatory approval process. Plants in this category include the Advanced Boiling Water Reactor ("ABWR") by General Electric ("GE") and Toshiba, Advanced Pressurized Water Reactor ("APWR") by Mitsubishi and the European Pressurized Water Reactor ("EPR") by Areva. ABWRs are in operation in Japan and have been considered for several sites in the United States. The APWR has been discussed for several US sites, but no license applications have been submitted to date. The EPR design is being built in Europe, and a modified version has been submitted for certification in the United States. The evolutionary designs have the same environmental characteristics as the current fleet of light water reactors.</p>	<p>ATTACHMENT BBBB BBBB. RETAINED for further screening.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT CCCCCC 27. Nuclear Advanced Light Water Reactor – Passive	<p>ATTACHMENT DDDDDDDD. Southern Company has made a commitment to this technology as evidenced by the ongoing construction of two AP1000 (1000 MW) nuclear units at the Vogtle site. In addition to the Westinghouse AP1000 design, this category includes the Economic Simplified Boiling Water Reactor (“ESBWR”), a passive Boiler Water Reactor (“BWR”) design under development by GE. The ESBWR design is not yet certified by the Nuclear Regulatory Commission (“NRC”). Westinghouse is also considering development of a larger passive plant, possibly an AP1600 (1600 MW). The current passive designs have the same environmental characteristics as the current fleet of light water reactors.</p>	<p>ATTACHMENT EEEEEEEE. RETAINED for further screening.</p>
ATTACHMENT FFFFFFFF 28. Nuclear Advanced Light Water Reactor – Modular	<p>ATTACHMENT GGGGGGGG. The economics of the smaller advanced modular reactor designs, such as the B&W Power (approximately 125 MW) are unclear. Additionally, these designs are years behind the evolutionary and passive plants in terms of both design development and licensing. They are expected to have the same environmental characteristics as other nuclear options.</p>	<p>ATTACHMENT HHHHHHHH. NOT RETAINED for further screening at this time due to development status.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT IIIIII. 29. Generation IV Nuclear	<p>ATTACHMENT JJJJJJJJ. There have been several generations of nuclear technology developed over the last 70 years. The AP1000 would be considered a Generation III+ design where a typical PWR or BWR would be considered Generation II. There are multiple Gen IV designs which can be categorized by the type of coolant they feature. This ranges from water to molten salt to liquid metal and even gases. The best Gen IV designs are “walk away safe” meaning they require no operator intervention to shut down. They are much cheaper to build, and they have a lower fuel cost than traditional machines. They have a smaller footprint but produce the same amount of power as a traditional reactor. They have shorter construction times. They produce substantially less radioactive waste and they are proliferation resistant meaning the fuel cannot be used for weapons. They are also capable of online refueling and load following.</p>	<p>ATTACHMENT KKKKKKKK. NOT RETAINED for further screening at this time due to development status.</p>



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT LLLLLL. 30. Nuclear Small Modular Reactor ("SMR")	<p>ATTACHMENT MMMMMMM. SMRs are nuclear reactors that typically have an output of 300 MW or less and correspond to the International Atomic Energy Agency ("IAEA") definition of a small-sized reactor. The modular component of SMRs refers to two attributes of the designs: (1) the ability of the reactor to be manufactured mostly in a factory setting and (2) each reactor is considered a separate module, thus allowing for phased installations at each site. SMR designs are currently in varying stages of design and development, globally. However, small nuclear reactors are not a new concept. For example, small nuclear reactors are a main energy source for the US Naval Fleet. Additionally, there are several operating nuclear reactors in the world that can be considered small. Conversely, SMRs are new designs that incorporate advancements in safety and technology. SMR manufacturers are proposing new Generation III+ and IV designs that incorporate concepts such as advanced safety design, smaller footprints and components, modular construction, smaller fuel sources, and new fuel designs. Several potential uses of SMRs have been identified, including remote and developing country electrification, retiring coal plant repowering, government and military base power, as well as incremental base load generation.</p>	ATTACHMENT NNNNNNN. RETAINED for further screening.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT OOOOOOO. 31. Solar Thermal Parabolic Trough	ATTACHMENT PPPPPP. Solar technologies based on focusing the sun's energy to heat a working fluid operate most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces the value of most solar thermal applications, and the high capital cost and large land area requirements are significant concerns. The technology has good environmental characteristics. One potential application of this technology is to use the steam that can be generated from this technology to augment the steam generated from a conventional fossil power plant or to augment thermal loads in processes such as post-combustion carbon capture, giving a lower-cost method of utilizing solar energy to power.	ATTACHMENT QQQQQQQ. NOT RETAINED for further screening at this time because solar PV would be more cost effective.
ATTACHMENT RRRRRRRR. 32. Solar PV	ATTACHMENT SSSSSSS. Cost has dropped significantly in recent years, Research continues to increase efficiency and reduce cost. Issues include the site-specific solar insolation resource and large land area requirements. Breakthroughs in PV technology could make this a very attractive alternative. The technology has excellent environmental aspects.	ATTACHMENT TTTTTTT. RETAINED for further screening.
ATTACHMENT UUUUUUUU. 33. Wind Power	ATTACHMENT VVVVVVV. Available wind resources in the Southeastern United States and the expected resulting capacity factors are not adequate to support significant utility-scale use of this technology, based on current economics. Advancing wind turbine technologies could increase potential viability.	ATTACHMENT WWWWWWW. RETAINED for further screening.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT XXXXXX. 34. Tall Tower/Large Rotor Wind Power	ATTACHMENT YYYYYYYY. Turbines with towers over 110m and rotor diameters greater than 110m. There are currently no known installations in the United States in this category, but improvements in turbine technology could allow for significantly higher capacity factors with a proportionately smaller increase in cost.	ATTACHMENT ZZZZZZZ. RETAINED for further screening.
ATTACHMENT AAAAAAAA. 35. Offshore Wind Power	ATTACHMENT BBBBBBBB. There is a significant resource in the Southeastern United States for offshore wind, but that resource needs to be directly measured to reduce uncertainty. As of the end of 2015, there is only one project in the United States moving forward with development and construction; the Block Island project (~30 MW)	ATTACHMENT CCCCCCCC. RETAINED for further screening.
ATTACHMENT DDDDDDDDD. 36. Municipal Solid Waste ("MSW")	ATTACHMENT EEEEEEEE. MSW generation has been used in some locales where landfills are too expensive or environmentally unacceptable. Thus, it has some potential but is highly site-specific and limited in ultimate quantity.	ATTACHMENT FFFFFFF. NOT RETAINED for further screening at this time due to limited interest and high level of environmental concern.
ATTACHMENT GGGGGGGG. 37. Dedicated Biomass (wood, etc.)	ATTACHMENT HHHHHHHH. Biomass (wood, wood waste, agricultural residues) is widely available in the Southeast. A dedicated biomass-fired power plant of 50 MW to 100 MW in size is feasible. Major consideration is obtaining fuel under a long-term contract at a reasonable (and low) price. The plant may rely on gasification of biomass, followed by a CT to convert the gas to electricity. Raw biomass tends to have a high transportation cost, due to its low energy-density in raw form. This places an upper limit on the size of a dedicated biomass-consuming power plant.	ATTACHMENT IIIIII. RETAINED for further screening.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT JJJJJJJJ. 38. Co-fired Biomass or Wood Waste	ATTACHMENT KKKKKKKK. C o-firing of switchgrass and wood waste has been demonstrated at several System power stations. Co-firing of these materials is now routine in AL and MS for green power pricing programs. Co-firing at up to 10% is probably the upper limit with traditional woody biomass. Co-firing at higher levels with advanced fuels such as pellets and torrefied wood is possible but is potentially detrimental to selective catalytic reduction ("SCR") emission reduction system catalysts.	ATTACHMENT LLLLLLLL. RETAINED for further screening.
ATTACHMENT MMMMMMM. 39. Landfill Gas	ATTACHMENT NNNNNNNN. C apped landfills produce methane gas through anaerobic digestion of the landfill contents. The gas has about half the energy of natural gas per unit and can be burned in engines or co-fired in natural gas boilers or turbines. Many environmental advantages with possible economic viability are present. A single large landfill may provide gas for 7 MW max.	ATTACHMENT OOOOOOOO. RETAINED for further screening.
ATTACHMENT PPPPPPPP. 40. Geothermal	ATTACHMENT QQQQQQQQ. G eothermal resources in the Southeastern United States are not adequate to support utility scale of this technology. Technologies are being monitored on a research level for potential niche applications.	ATTACHMENT RRRRRRRR. NOT RETAINED for further screening at this time due to limited applicability in Georgia Power's and Southern Company's territory.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT SSSSSSSS 41. Solar Stirling Dish	ATTACHMENT TTTTTTTT. The Dish Stirling engine operates as an externally heated piston-driven prime mover. In a solar Stirling dish system, a dish is used to capture and focus sunlight to provide heat for the Stirling engine. As with the parabolic trough and other reflector systems, diffuse solar insolation due to clouds and haze in the Southeast greatly reduces the effectiveness and value of solar Stirling dish. This technology has good environmental characteristics, but applicability is very limited in the Southeastern United States.	ATTACHMENT UUUUUUUU. NOT RETAINED for further screening at this time due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
ATTACHMENT VVVVVVYY 42. Solar Central Receiver Technology	ATTACHMENT WWWWWWWW. This technology is commonly referred to as a "power tower", where an array of mirrors is focused on a specific area on a tower that contains a receiver (boiler) where steam is made directly. It works most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces its value, and the high capital cost and large land area requirements are significant concerns. This technology has good environmental characteristics.	ATTACHMENT XXXXXXXX. NOT RETAINED for further screening at this time due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.
ATTACHMENT YYYYYYYY 43. Compact Linear Fresnel Reflector	ATTACHMENT ZZZZZZZZ. Rows of solar collectors reflect solar radiation onto a linear receiver above the solar field in which pressurized water is converted into steam. It works most effectively in direct sunlight. Diffuse solar insolation due to clouds and haze in the Southeast reduces its value, and the high capital cost and large land area requirements are significant concerns. This technology exhibits good environmental characteristics.	ATTACHMENT AAAAAAAA. NOT RETAINED for further screening at this time due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.



ATTACHMENT ZZZZ. Technology	ATTACHMENT AAAAA. Description	ATTACHMENT BBBB. Status
ATTACHMENT BBBB. 44. Ocean Energy & Hydrokinetic Generation	<p>ATTACHMENT CCCCCCCCCC. Ocean energy and hydrokinetic generation includes power generation from waves, ocean tides, and river current. Specific research has begun to be conducted in these areas defining the resources and developing technologies that can utilize these resources. They have the potential to negatively affect estuarine environments.</p>	<p>ATTACHMENT DDDDDDDDD. NOT RETAINED for further screening at this time due to cost uncertainties, level of development, and limited applicability in Georgia Power's and Southern Company's territory.</p>
ATTACHMENT EEEEEEEE. 45. Ocean Thermal Generation	<p>ATTACHMENT FFFFFFFF. The temperature difference between surface and deep ocean waters can be used to drive an ammonia ("NH₃") or other low-temperature power cycle to produce power. In most situations, tropical locations with deep ocean near shore are sought. There are environmental concerns with releasing cold bottom water at the ocean surface and with the potential for NH₃ release.</p>	<p>ATTACHMENT GGGGGGGGG. NOT RETAINED for further screening at this time due to cost uncertainties, level of development, lack of good sites in Georgia Power's and Southern Company's territory, and potential environmental considerations.</p>
ATTACHMENT HHHHHHHHHH. 46. Direct-fired Supercritical CO ₂ cycle	<p>ATTACHMENT IIIIIIII. Carbon dioxide used in a closed-loop direct-fired Brayton power cycle has particular advantages due to the nature of the fluid properties in a supercritical state. Also named the "Allam Cycle", this technology uses recuperation to increase efficiency, but can also use higher temperature operation as would any thermodynamic cycle. The technology is fired with gaseous fuel, and due to the nature of the cycle, creates pipeline-ready CO₂ for a zero- or near-zero emissions plant. Material and mechanical design present current challenges. There is ongoing industry development work.</p>	<p>ATTACHMENT JJJJJJJJJ. NOT RETAINED for further screening at this time due to current level of development.</p>

ATTACHMENT KKKKKKKKKK.



ATTACHMENT LLLLLLLLLL. Table B-3 lists the technologies that were retained from the preliminary screening and used as inputs for the secondary screening.

ATTACHMENT MMMMMMMMM. *Table B-3: Secondary Screening Technologies*

ATTACHMENT NNNNNNNNNN. <u>G</u> <u>AS-FUELED</u>	ATTACHMENT OOOOOOOOO. <u>NUCLEAR</u>
ATTACHMENT PPPPPPPPPP. CT Conventional/Advanced	ATTACHMENT QQQQQQQQQQ. Advanced LWR – Evolutionary
ATTACHMENT RRRRRRRRRR. C C Conventional/ Advanced	ATTACHMENT SSSSSSSSS. A dvanced LWR – Passive
ATTACHMENT TTTTTTTTTT. Phos phoric Acid Fuel Cell	ATTACHMENT UUUUUUUUUU. S mall Modular Reactor
ATTACHMENT VVVVVVVVVV. MC FC & SOFC	ATTACHMENT WWWWWWWWW.
ATTACHMENT XXXXXXXXXX. Reci procating Engines	ATTACHMENT YYYYYYYYYY. R <u>ENEWABLES</u>
ATTACHMENT ZZZZZZZZZZ. Micro turbines	ATTACHMENT AAAAAAAA. Solar PV
ATTACHMENT BBBBBBBBBB.	ATTACHMENT CCCCCCCCCC. Wind Power
ATTACHMENT DDDDDDDDDDD. E <u>NERGY STORAGE</u>	ATTACHMENT EEEEEEEEEEE. Tall Tower Large Rotor Wind Power
ATTACHMENT FFFFFFFFFF. Pum ped Storage Hydro	ATTACHMENT GGGGGGGGGG. Offshore Wind Power
ATTACHMENT HHHHHHHHHHH. C ompressed Air Energy Storage – Gen I	ATTACHMENT IIIIIIIIII. Dedicated Biomass
ATTACHMENT JJJJJJJJJJJ. Com pressed Air Energy Storage – Gen II	ATTACHMENT KKKKKKKKKK. Co-fired Biomass or Wood Waste
ATTACHMENT LLLLLLLLLL. Adv anced Lead Acid Batteries	ATTACHMENT MMMMMMMMM. Landfill Gas
ATTACHMENT NNNNNNNNNN. L ithium-Ion Batteries	ATTACHMENT OOOOOOOOOO.

ATTACHMENT PPPPPPPPPP.

ATTACHMENT QQQQQQQQQQ.



ATTACHMENT RRRRRRRRRRRR. Table B-4 summarizes the list of technologies that were retained from the secondary screening and used as inputs for the expansion planning process.

ATTACHMENT SSSSSSSSSS.

ATTACHMENT TTTTTTTTTT. Table B-4: Expansion Planning Technologies

ATTACHMENT UUUUUUUUUU. G AS-FUELED	ATTACHMENT VVVVVVVVVV. R ENEWABLES
ATTACHMENT WWWWWWWWWWWWW. CT Conventional	ATTACHMENT XXXXXXXXXX. S olar PV
ATTACHMENT YYYYYYYYYYYY. CC Advanced	ATTACHMENT ZZZZZZZZZZ.

ATTACHMENT AAAAAAAAAAAA.

ATTACHMENT BBBBBBBBBBBB. Note: Future environmental controls such as SCR with CT and CCC with CC may be required to align with the scenario planning process.

ATTACHMENT CCCCCCCCCCCC.

ATTACHMENT DDDDDDDDDDDD.



ATTACHMENT EEEEEEEEEE. SUMMARY OF THE SYSTEM POOLING ARRANGEMENT

ATTACHMENT FFFFFFFFFF. Introduction

ATTACHMENT GGGGGGGGGGGG. Georgia Power is a member of the Pool, which consists of the Operating Companies.⁷ The Operating Companies function as a single, integrated public-utility system through adherence to the Southern Company System Intercompany Interchange Contract (“IIC”), an agreement on file with FERC. SCS acts as agent for the Operating Companies in the administration of the IIC. The IIC provides a framework whereby the generating resources of the Operating Companies are operated in a coordinated and integrated fashion to economically serve their aggregate firm obligations, as well as to engage in shorter term transactions in the wholesale markets. Using traditional concepts of economic dispatch, the Pool deploys available generation to satisfy the aggregate obligations of the System at any given time in a reliable and economic fashion. The IIC also provides for coordinated planning between the Operating Companies and for the sharing of temporary surpluses and deficits of capacity. The IIC ensures that the after-the-fact accounting associated with joint System dispatch (energy) and reserve sharing (capacity) is handled in accordance with the principles set forth in that agreement. It should be noted that the coordinated planning process for the Retail OpCos is functionally separate from the planning process for Southern Power.⁸

⁷ For purposes of the Intercompany Interchange Contract (IIC), Operating Companies currently consist of the Southern Operating Companies (Alabama Power Company, Georgia Power Company, Mississippi Power Company, and Southern Power Company) as well as Gulf Power Company. On January 1, 2019, Southern Company completed the sale of Gulf Power Company to NextEra Energy. Gulf Power will remain part of the Pool for the Transition Period and be treated similarly to the 12 months prior to closing. The Transition Period is defined as five years from the date the transaction closes with the possibility of an extension for 2 additional years. Although Southern Company and NextEra Energy agreed a 5 to 7-year Transition Period will likely be needed, Gulf Power Company has the right to withdraw from the Pool at any time with 180 days' notice. The details outlining Gulf Power Company's participation in the Pool as a non-affiliate are included in Appendix A to IIC that was filed at FERC on July 3, 2018.

⁸ Gulf Power Company will develop its own resource plans to be verified by SCS and aggregated with the plans of the other Pool members. Gulf Power Company is expected to have adequate resources to reliably serve its own obligations and is required to provide sufficient information to demonstrate compliance with such expectation during the Transition Period. No Operating Company specific information for the Southern Company Operating Companies will be shared with NextEra Energy or Gulf Power Company.



ATTACHMENT HHHHHHHHHHHH. Relationship of the Operating Companies under the IIC

ATTACHMENT I|||||||||. The Southern Company Pool is a coordinated Pool, not a centralized Pool. Although the generating facilities of each Operating Company are committed to a centralized economic dispatch, each individual Operating Company retains the right and the responsibility for providing the generation and transmission facilities necessary to meet the requirements of its customers. Each Operating Company has its own management that reports to its own board of directors, with the management and the board of directors of each Operating Company being directly responsible for making the decisions that affect that Operating Company and its customers. They are also responsible for working with local regulators and adhering to the requirements of state law.

ATTACHMENT JJJJJJJJJJJJJ. Accordingly, each Operating Company has its own distinct characteristics in regard to types of generation and load. For example, Alabama Power, Georgia Power, and Southern Power bring hydro and nuclear generating capacity to the Pool, while the other Operating Companies do not. Similarly, the load characteristics of the Operating Companies vary due to the types of customers each brings to the Pool. The differing economies within each Operating Company territory and customer base lead to different load growth rates and load shapes for each Operating Company.

ATTACHMENT KKKKKKKKKKKK. The IIC provides for an Operating Committee that consists of one representative of each Southern Operating Company and SCS, with the SCS representative acting as a non-voting Chairman.⁹ The functional separation of certain activities of Southern Power restricts the participation of its Operating Committee member in some matters (such as discussions and recommendations involving the coordinated planning of the Retail OpCos). A unanimous vote of the Operating Committee voting members is required in order to change the IIC.

ATTACHMENT LLLLLLLLLL. Interconnections

ATTACHMENT MMMMMMMMMMM. The Operating Companies are interconnected with 12 non-associated utilities through 61 different transmission facilities. These

⁹ As of January 1, 2019, Gulf Power will not have a representative on the Operating Committee but will have a designated contact to be notified of changes to the IIC or policies, practices, or procedures used in its implementation.



transmission lines are operated at voltages of 46 kV, 69 kV, 115 kV, 161 kV, 230 kV, and 500 kV, and include facilities that are operated normally open. The non-associated utilities with which the System is interconnected are shown in Table C-5.

ATTACHMENT NNNNNNNNNNNN. *Table C-5: Non-Associated Utilities*

ATTACHMENT OOOOOOOOOOO. Florida Power & Light Company	ATTACHMENT PPPPPPPPPPPP. Duke Energy Florida
ATTACHMENT QQQQQQQQQQQ. JEA	ATTACHMENT RRRRRRRRRRR. City of Tallahassee
ATTACHMENT SSSSSSSSSSS. Duke Energy Corporation (Carolinas)	ATTACHMENT TTTTTTTTTT. South Carolina Electric & Gas Company
ATTACHMENT UUUUUUUUUUUU. Tennessee Valley Authority	ATTACHMENT VVVVVVVVVVV. South Carolina Public Service Authority
ATTACHMENT WWWWWWWWWWW. Entergy Corporation	ATTACHMENT XXXXXXXXXX. Crisp County Power Commission
ATTACHMENT YYYYYYYYYYY. PowerSouth Energy Cooperative	ATTACHMENT ZZZZZZZZZZ. South Mississippi Electric Power Association

ATTACHMENT AAAAAAAAAAAA.

ATTACHMENT BBBBBBBBBBBBBB. Basic Principles of the IIC

ATTACHMENT CCCCCCCCCCCC. The basic principles of the IIC can be summarized as follows.

1. Each Operating Company submits its load and generation to the Pool for joint commitment and economic dispatch.
2. Energy Principles:
 - a. Each Operating Company retains its lowest cost resources to serve its customers.
 - b. An Operating Company's excess energy is next made available to the other Operating Companies to serve their customers if the cost of the Pool energy is less than the cost of energy from their own resources.
 - c. Energy in excess of that necessary to serve the Operating Companies' customers is marketed by the Pool to the wholesale markets.
3. The IIC provides for coordinated planning among the Retail OpCos and for the sharing among all Operating Companies of temporary surpluses and deficits of capacity.¹⁰
4. Under the IIC, each Operating Company shares in the benefits and pays its share of the costs resulting from their coordinated operations.

10 Gulf Power Company will develop its own resource plans to be verified by the Agent and aggregated with the plans of the other Pool members.



ATTACHMENT DDDDDDDDDDDDDDD. Participation in the Southern Company Pool provides benefits to the Operating Companies and to their customers. This not only enhances Georgia Power's ability to provide reliable, low-cost electric service to its customers but also to achieve economies of scale in any required investments. Benefits of Pool participation include:

- Staggering construction of new generating facilities so that each retail Operating Company can construct and install the optimum sized generating facilities while utilizing economies of scale;
- Sharing temporary surpluses and deficits of generating capacity that can arise as a result of coordinated planning or other circumstances (e.g., staggered construction schedules, variations in load patterns, load forecast uncertainties, etc.);
- Coordinating scheduled maintenance to provide greater flexibility, including major maintenance requiring relatively long unit outages, as well as mitigating the cost impact (to customers) of these required outages;
- Carrying a lower generation planning reserve margin (due primarily to System load diversity), which enables each Operating Company to have a lower investment in generating resources;
- Providing reliable service with shared operating reserve requirements (which puts downward pressure on fuel costs);
- Access to lower cost energy from other Operating Companies;
- Enhanced reliability of electric service through the use of transmission interconnections to provide backup service in case of emergencies as well as providing the ability to import lower cost energy when available; and
- Acting as a Pool (instead of individual Operating Companies) to identify shorter term purchase and sale opportunities in the wholesale markets that may be available from time to time.

ATTACHMENT EEEEEEEEEEEE. Basic Operation of the IIC

ATTACHMENT FFFFFFFFFF. The concept of economic dispatch, which seeks to minimize the total System production cost, is one of the major benefits of the Pool. The generating assets of all the Operating Companies in the Pool are committed and dispatched as a common System without regard to the ownership of each generating facility. Subject to operational constraints and reliability considerations, the lowest cost generation assets are dispatched during each hour to meet the total needs of the customers of all the Operating Companies. The goal of this process is to ensure that the lowest cost energy is produced



every hour. It also should be reiterated that each Operating Company retains its lowest cost generation to serve that Operating Company's customers.

ATTACHMENT GGGGGGGGGGGGG. The Pool also interfaces with the wholesale markets on behalf of the Operating Companies for both sales and purchases. When the Pool has excess power available, it will pursue wholesale sales opportunities for which there is a reasonable expectation that the transaction will result in positive net margin for the Operating Companies. There are two primary reasons for the Pool to seek purchase opportunities: (1) economics; and (2) reliability. The Pool will pursue purchase opportunities from the wholesale markets if such purchases are expected to be more economical than System resources (again, subject to operational constraints and System reliability). In the event the Pool experiences reliability challenges, then the Pool may seek purchases in response to such operating conditions.

ATTACHMENT HHHHHHHHHHHHH. Reserve Sharing

ATTACHMENT IIIIIIIII. As noted in the introduction, the IIC contains capacity provisions, commonly referred to as "reserve sharing," that provide for a sharing of temporary generating capacity surpluses and deficits that are a result of coordinated planning or other circumstances. As participants in the coordinated operation of the integrated electric system, each Operating Company enjoys the same level of service reliability. In any given month, however, one or more Operating Companies will have a temporary surplus or deficit of capacity relative to the overall level of actual System reserves. Consistent with the goal of sharing in the benefits and burdens of the coordinated and integrated electric system, the reserve sharing provisions of the IIC provide for the equitable allocation of such temporary surplus or deficit capacity. The resulting purchase and sale of capacity is transacted on a monthly basis.

ATTACHMENT JJJJJJJJJJJJJ. Reserve sharing is determined by comparing each Operating Company's load responsibility with its respective capacity resources recognized through the coordinated planning process. The Operating Companies must own or purchase sufficient capacity (including capacity available for load service and that which is unavailable due to forced outage, partial outage, and maintenance outage) needed to reliably serve their respective load responsibilities. Capacity above that amount is considered reserve capacity, and each Operating Company is responsible for a portion of such reserve capacity based



upon historical peak load ratios. If an Operating Company's reserve capacity is less than its reserve responsibility, that Operating Company will make reserve sharing payments under the IIC for the month.

ATTACHMENT KKKKKKKKKKKKKK. Each Operating Company develops an annual charge (payments are based on monthly capacity worth) based upon the cost of its most recently installed or purchased peaking resource(s). The Operating Companies that are "selling" capacity to the Pool will receive a payment from the Pool based upon their respective capacity rates. The Operating Companies that are "buying" capacity from the Pool will make payments to the Pool based upon the weighted average of the capacity rates of the "selling" Operating Companies. In this way, all the buying Operating Companies pay the same composite cost in a given month for reserve sharing purposes. By definition, the amount by which one or more Operating Companies are "short" (make payments) will be equal to the amount by which one or more Operating Companies are "long" (receive payments).

ATTACHMENT LLLLLLLLLLLL. Energy Transactions

ATTACHMENT MMMMMMMMMMMMM. Energy transactions within the Pool are accounted for on an hour-to-hour basis, with the accounting occurring after-the-fact utilizing the actual flows among the Operating Companies.

ATTACHMENT NNNNNNNNNNNNN. The actual real-time operation of the System is based upon the concept of economic energy dispatch, which through on-line computer control assures that available generation is dispatched so as to choose the most economical generation available to serve the total System obligation at any given time. An adequate set of lowest-cost generating resources is committed in advance to meet the total System obligation, with due regard for generation requirements associated with service area protection, voltage control, unit protection, and other operating limitations considerations.

ATTACHMENT OOOOOOOOOOOOO. For billing purposes under the IIC, each Operating Company is deemed to have retained its lowest-cost energy resources (most notably hydro and nuclear) to serve its own territorial customers, plus whichever of its resources that may have been operating outside of economic dispatch for purposes of service area protection or voltage control. To the extent an Operating Company's generation exceeds its own load obligations, such energy is sold to the Pool under the IIC. If an



Operating Company's generation is not equal to or greater than its own load obligations, the difference is purchased from the Pool. The energy rate for energy sold to or purchased from the Pool by each Operating Company is referred to as the Associated Interchange Energy Rate and represents the incremental System cost of serving the Operating Companies' aggregate firm obligations. Under the IIC, the determination of which Operating Companies are buying from and which are selling to the Pool is made on an hourly basis, and an invoice that accounts for these energy transactions is rendered monthly.

ATTACHMENT PPPPPPPPPPPP. Peak-Period Load Ratios

ATTACHMENT QQQQQQQQQQQQQQ. Peak-Period Load Ratios are utilized in the allocation of certain energy and capacity transactions by the Pool with non-associated systems, hydro regulation energy losses, increases in cost due to hydro regulation, and other allocations provided for in the IIC and the Manual to the IIC.

ATTACHMENT RRRRRRRRRRRRRR. The Peak-Period Load Ratios for each contract year are based upon the prior year's actual peak-period energy in the months of June, July, and August for each Operating Company. The peak period is defined to be the 14 hours between 7:00 a.m. and 9:00 p.m. of each weekday, excluding holidays. The System peak-period energy is equal to the sum of all the Operating Companies' peak-period energy.

ATTACHMENT SSSSSSSSSSSS. The Peak-Period Load Ratios are determined by dividing each Operating Company's summation of the June, July, and August actual weekday peak-period energy loads by the total System June, July, and August actual weekday peak-period energy loads.

ATTACHMENT TTTTTTTTTTTT.



ATTACHMENT UUUUUUUUUUUUU. APPLICATION FOR CERTIFICATION OF CAPACITY FROM PLANT SCHERER UNIT 3

ATTACHMENT VVVVVVVVVVVVV. Executive Summary

ATTACHMENT WWWWWWWWWWWWWWW. Capacity Resources

ATTACHMENT XXXXXXXXXXXXXX. Georgia Power seeks to certify approximately 25 MW of capacity from Plant Scherer Unit 3 pursuant to the terms and conditions offered in this filing. This capacity is made available to the retail jurisdiction pursuant to the plan approved by the Commission in its Orders in Docket No. 26550-U. See *Order approving Georgia Power Company's Proposal to Offer Certain Wholesale Capacity Blocks to Retail Jurisdiction*, Docket No. 26550-U (July 30, 2008) (the "Plan"). The Plan provided that this capacity would be offered to the retail jurisdiction (1) on terms equivalent to that which the Company could obtain in the then-current markets, (2) in a manner that would not adversely affect the Company's ability to continue to sell such resources into the wholesale markets, and (3) in a manner such that the RFP process was not adversely affected.

ATTACHMENT YYYYYYYYYYYYYY. Georgia Power's offer of the approximately 25 MW of wholesale capacity from Plant Scherer Unit 3 is consistent with the mandates of the Commission-approved Plan. Additional information on the Company's offer can be found in the Selected Supporting Information section of Technical Appendix Volume 1. In accordance with the Plan, the Company now files for certification pursuant to Commission Rule 515-3-4-04(3)(f) and O.C.G.A. § 46-3A-3. The Company requests that Acceptance and Certification, or rejection, of this offer be determined in the final decision issued in this case.

ATTACHMENT ZZZZZZZZZZZZ. History of the Capacity Resource Offer

ATTACHMENT AAAAAAAAAAAAAAA. On December 20, 2007, the Commission initiated a proceeding to consider whether it has the authority to require Georgia Power to first make capacity available to retail customers through a competitive solicitation before entering into any new contracts with wholesale customers. The Company and various intervenors submitted comments on the matter. Based upon the comments received, the Commission amended its Procedural and Scheduling Order in Docket No. 26550-U to provide the Parties an opportunity to make a good faith effort to resolve the matter and develop a resource specific plan of action. The Company conferred with other Parties and



developed a plan that would provide for the Company to offer certain wholesale capacity blocks to the retail jurisdiction on a one-time basis. At its Administrative Session on July 15, 2008, the Commission approved this Plan, and, subsequently, the Commission Order approving the Plan was filed on July 30, 2008. The Commission has previously certified several offers to bring resources to the retail jurisdiction under the Plan, including resources at Plant Scherer Unit 3 and resources from Wholesale Blocks 1, 2-4, and 5 & 6.

ATTACHMENT BBBBBBBBBBBB. The Company's offer in this 2019 IRP to bring additional capacity from Plant Scherer Unit 3 to the retail jurisdiction is the next step in the implementation of the Plan and aligns with the Company's recognition of the importance of maintaining fuel diversity for the benefit of retail customers.

ATTACHMENT CCCCCCCCCCCCCC. As stated in CHAPTER 11. of the 2019 IRP Main Document, as required by the July 30, 2008 Order in Docket No. 26550-U, Georgia Power is offering approximately 25 MW of capacity from Plant Scherer Unit 3 to the retail jurisdiction to serve retail customers when the capacity becomes available on January 1, 2020. Please see the Selected Supporting Information section of Technical Appendix Volume 1 for the Company's offer of this capacity.

ATTACHMENT DDDDDDDDDDDDDDD. Certification Process

ATTACHMENT EEEEEEEEEEEE. Terms of Purchase

ATTACHMENT FFFFFFFFFF. In conjunction with adherence to the Plan, the Company recognizes the importance of maintaining fuel diversity and, thus, proposes to take the opportunity to acquire additional capacity from the Company's most economical coal resource, Plant Scherer. The terms of the offer of the Plant Scherer Unit 3 wholesale block capacity to the retail jurisdiction are found in the Selected Supporting Information section of Technical Appendix Volume 1.

ATTACHMENT GGGGGGGGGGGGG. Cost of Purchase

ATTACHMENT HHHHHHHHHHHHHHH. The Company proposes to offer the Plant Scherer Unit 3 wholesale block capacity under the same Market Differential Adjustment ("MDA") construct utilized in previous offers. The MDA would serve to impact base rates by adjusting projected retail revenues. The offer included in the Selected Supporting



Information section of Technical Appendix Volume 1 details the purchase cost for the Plant Scherer Unit 3 wholesale block capacity.

ATTACHMENT I||||||||||. Proposed Ratemaking Treatment

ATTACHMENT JJJJJJJJJJJJJJJ. The assets shall be placed in retail rate base at their current book value, accompanied by the utilization of an MDA. To ensure the proper allocation of the MDA to the retail jurisdiction, the MDA will be treated as an adjustment to retail base revenues available for regulatory purposes, thereby resulting in an adjustment in retail base revenue requirements.

ATTACHMENT KKKKKKKKKKKKKKK. Similar to other assets in retail rate base, all prudently incurred actual fuel costs associated with the resources will be recovered through the fuel cost recovery process. The assets shall be placed in retail rate base and treated in the same manner as all other generation assets in retail rate base. There are no additional warranties for performance, and the recovery of all costs will be consistent with the recovery for cost on all other retail rate base generation assets. For example, costs incurred due to a change in law will be included in retail rate base; the Company does not warrant any level of availability or heat rate; actual non-fuel O&M costs shall be recovered in retail base rates. For additional details on the offer, please see the Selected Supporting Information section of Technical Appendix Volume 1.

ATTACHMENT LLLLLLLLLLLL. Depreciation Analysis

ATTACHMENT Moooooooooooo. The estimated depreciation schedule for Plant Scherer Unit 3 wholesale block capacity can be found in the Selected Supporting Information section of Technical Appendix Volume 1.

ATTACHMENT NNNNNNNNNNNNN. Cost Benefit Analysis

ATTACHMENT Ooooooooooooo. As explained in CHAPTER 11. of the 2019 IRP Main Document, this 2019 IRP continues the recent trend of decertifying significant amounts of coal capacity. The requirement to offer certain wholesale blocks to the retail jurisdiction provides an opportunity within the 2019 IRP to consider maintaining some additional fuel diversity as primarily older coal units retire. In the IRP the Commission will be able to consider the Company's offer with a complete understanding of the impacts of further



reliance on gas as the company continues to grow its renewable resource portfolio. The majority of Plant Scherer Unit 3 output is already used to serve retail customers; as such, Plant Scherer as a whole continues to provide economic benefits to customers. In 2009, the Commission approved the return of 78 MW of Plant Scherer Unit 3 to the retail jurisdiction. As the Company continues to rely more heavily on gas resources, coal continues to be important to the strategy of maintaining fuel diversity. Maintaining the capacity and energy diversity of Plant Scherer Unit 3 is even more important during this period of transition to more natural gas and renewable forms of generation. Retaining this capacity for retail service also recognizes the benefits that Plant Scherer Unit 3 has provided to customers over its life. Please refer to the Company's offer presented in the Selected Supporting Information section of Technical Appendix Volume 1 for the economics of the Plant Scherer Unit 3 wholesale block capacity.

ATTACHMENT PPPPPPPPPPPPPP. Analysis of Transmission Impacts

ATTACHMENT QQQQQQQQQQQQQQQQ. There are no transmission facilities added, modified, or avoided as a result of this certification request.

ATTACHMENT RRRRRRRRRRRRRR. Impact on 2019 IRP

ATTACHMENT SSSSSSSSSSSSS. The return to retail jurisdiction of the Plant Scherer Unit 3 wholesale block capacity is reflected in the various analyses presented in the 2019 IRP.

ATTACHMENT TTTTTTTTTTTTT. Commission Rule Exception to the RFP Requirement

ATTACHMENT UUUUUUUUUUUUUU. Pursuant to the Commission's Order Approving Georgia Power Company's Proposal to Offer Certain Wholesale Capacity Blocks to the Retail Jurisdiction, the Company is required to offer the Plant Scherer Unit 3 capacity to retail customers. As part of the Commission's Order, the Company agreed to offer the wholesale blocks as they become available to the retail jurisdiction (1) on terms equivalent to that which the Company could obtain in the then-current wholesale market, (2) in a manner that would not adversely affect the Company's ability to continue to sell such resources into the wholesale market, and (3) in a manner that the RFP process is not adversely affected. As noted earlier, the Company has made several offers to the



Commission since the Commission Order approving the Company's Proposal was issued on July 30, 2008. The Order clearly recognizes the importance of timing of the offers to the ability to remarket capacity and the importance of the IRP in that process. Through prior Orders certifying wholesale to retail capacity, the Commission has exempted that capacity from the Commission's RFP rules as specified in Commission Rule 515-3-4-.04. Pursuant to Commission Rule 515-3-4-.04(3)(f)(5), which exempts from the RFP requirement "any supply-side resource that would provide power at a capacity level of 30 MW or less," the Company requests that the Plant Scherer Unit 3 offer of 25 MW of capacity be exempted as provided by Commission Rule.

ATTACHMENT VVVVVVVVVVVVVV. Conclusion

ATTACHMENT WWWWWWWWWWWWWWWWW. As set forth in the Company's 2019 IRP, Georgia Power's current supply-side plan, which incorporates the requested certification contained herein, is sufficient to provide cost-effective and reliable sources of capacity and energy for customers. The request contained in this 2019 Certification Application is in the public interest and substantially complies with the relevant Commission rules. Therefore, the Company requests that the Commission Accept and Certify this offer.



ATTACHMENT XXXXXXXXXXXXXXX. APPLICATION FOR CERTIFICATION OF CAPACITY UPGRADES AT PLANT GOAT ROCK UNITS 9-12

ATTACHMENT YYYYYYYYYYYYYY. Executive Summary

ATTACHMENT ZZZZZZZZZZZZZ. Capacity Resources

ATTACHMENT AAAAAAAAAAAAAAA. As discussed in CHAPTER 9. of the 2019 IRP Main Document, Georgia Power plans to make needed investments in its hydro fleet to maintain operations for the benefit of customers. As part of this investment, the Company is replacing aging turbines at the Goat Rock hydro facility with updated turbine technology. The new turbine designs will have more capacity, higher efficiency, fewer maintenance requirements, and easier, safer access for those maintenance needs. This upgrade to Goat Rock will increase capacity from 5 MW to approximately 9.6 MW for each of Units 3-6 by the summer of 2023. The total capacity of the entire Goat Rock hydro facility will grow from approximately 39 MW to approximately 57 MW serving customers, or nearly a 50 percent increase in capacity. As a result of the turbine replacements, Plant Goat Rock Units 3-6 will become Plant Goat Rock Units 9-12. To facilitate the needed upgrade to the Goat Rock hydro facility, the Company is seeking a Certificate Amendment as required by O.C.G.A. § 46-3A-3(b) and Commission Rule 515-3-4-08.

ATTACHMENT BBBBBBBBBBBBBB. Increasing the capacity of Goat Rock will assure a reliable supply of electric capacity and energy for the Company's retail customers, while also resolving flow imbalance concerns on the Chattahoochee River. Currently, there is a flow imbalance in the Chattahoochee River hydro fleet that occurs daily during peak periods. On the Chattahoochee River, Goat Rock Dam is situated downstream of Bartletts Ferry Dam (Lake Harding), and upstream of Oliver and North Highlands Dams; all are located upstream of the City of Columbus and provide peaking power. They also provide a minimum river flow through the Columbus downtown Riverwalk area. Bartletts Ferry, Oliver, and North Highlands Dams all discharge approximately 13,000 cubic feet per second ("cfs"), whereas Goat Rock can only discharge approximately 9,000 cfs at its present size. To accommodate the higher flow from Bartletts Ferry (flow imbalance), Georgia Power currently has to draw Goat Rock Lake down further each day. If the lake were not drawn down further each day, then during the next day's peak, Goat Rock would be inundated with Bartletts Ferry peak power flows and would have to spill water, resulting in the spilled portion of the



flow not generating power. Additionally, because Georgia Power has to run the units at Goat Rock longer each day to correct for the flow imbalance, the generation extends to non-peak power periods, which is not the most economical use of the water.

ATTACHMENT CCCCCCCCCCCCCCCC. Finally, in addition to resolving the issues caused by the flow imbalance the upgrade to Goat Rock will provide critical capacity and dynamic reactive support to the area's transmission system, especially critical during peak power demand periods.

ATTACHMENT DDDDDDDDDDDDDDD. History of Capacity Resource Additions

ATTACHMENT EEEEEEEEEEEEEEE. Georgia Power's Goat Rock hydro facility is located on the Chattahoochee River about 10 miles north of Columbus, Georgia. The dam and powerhouse were constructed during the period of 1910-1912. The powerhouse contains four horizontal, double-runner Francis turbines and two horizontal propeller turbines with a total capacity of approximately 39 MW. Units 1 and 2, each rated at 3 MW, went into service in 1912. (These units were later renumbered to Units 7 and 8 when a capacity upgrade of 6 MW each was approved by the Commission in 2001.) Unit 3 came online in 1915, Unit 4 in 1920, Unit 5 in 1955, and Unit 6 in 1956. The development is licensed as part of the Middle Chattahoochee Project, FERC Project No. 2177. The license for Plant Goat Rock and its sister developments, Plants Oliver and North Highlands, expires on December 26, 2034.

ATTACHMENT FFFFFFFFFFFFFF. On December 13, 1971, Georgia Power filed an application with the Federal Power Commission (now FERC) to add two new 50 MW units at the Bartletts Ferry Project, FERC Project No. 485. Bartletts Ferry is located on the Chattahoochee River immediately upstream of the Goat Rock hydro facility. At the time the application was filed, it was realized that construction of the two new units at Bartletts Ferry would result in a significant imbalance in flows when compared to the hydraulic capacity at Goat Rock. By letter dated March 13, 1972, FERC requested that Georgia Power amend its license for Project 2177 to redevelop Goat Rock dam. FERC ultimately removed the requirement for Georgia Power to amend its license. However, Southern Company continued to investigate possibilities for redeveloping Plant Goat Rock, and on December 15, 2000, the Company filed an application for certification at the Commission for capacity upgrades for Plant Goat Rock Units 1 and 2. This solution improved the hydraulic imbalance



with Plant Bartletts Ferry upstream and with Plants Oliver and North Highlands downstream while satisfying the letter and intent of prior FERC Orders. At a Special Administrative Session on July 12, 2001, the Commission granted the application for certification of the upgrades to the Goat Rock hydro facility, which also resulted in the renumbering of Units 1 and 2 to Units 7 and 8. For additional details, see Docket No. 12499-U. With the requested capacity upgrades at Plant Goat Rock Units 9-12, the Company will be able to fully resolve the flow imbalance concerns on the Chattahoochee River.

ATTACHMENT GGGGGGGGGGGGGGG. Cost Benefit Analysis

ATTACHMENT HHHHHHHHHHHHHHHH. As discussed above, the upgrades will correct a flow imbalance in the Chattahoochee River hydro fleet, which is currently being addressed through operating guidelines. As such, increasing the capacity of the units will make daily operations more economical. In addition to providing critical support to the area's transmission system, these units provide peaking power as well as provide a minimum river flow through the Columbus downtown Riverwalk area. As the Georgia Power fleet continues to transition, maintaining fuel diversity will be critical, and it is important to continue investment in the Company's hydro generating resources. Investing in these capacity upgrades is a key piece of that strategy, as outlined in this 2019 IRP.

ATTACHMENT IIIIIIIIIII. Upgrading Goat Rock Units 3-6 will provide many needed benefits for customers as articulated in the foregoing sections. The economics of the project are shown in Selected Supporting information found in Technical Appendix Volume 1 and must be considered against the broader need to correct the flow imbalance, preserve ongoing fuel diversity, and improve resource flexibility provided by maintaining these critical resources to serve customers. For information on the costs and benefits associated with the capacity upgrades at the Goat Rock hydro facility, see the Selected Supporting Information section of Technical Appendix Volume 1.

ATTACHMENT JJJJJJJJJJJJJJJ. Proposed Ratemaking Treatment

ATTACHMENT KKKKKKKKKKKKKKK. The capacity upgrades at the Goat Rock hydro facility will be recovered through traditional (rate base and revenue requirement) ratemaking, similar to the existing Goat Rock hydro facility.



ATTACHMENT LLLLLLLLLLLLLL. Analysis of Transmission Impacts

ATTACHMENT MMMMMMMMMMMMMMM. There are no transmission facilities added, modified, or avoided as a result of this certification request.

ATTACHMENT NNNNNNNNNNNNNNN. Impact on 2019 IRP

ATTACHMENT OOOOOOOOOOOOOOO. The capacity at Plant Goat Rock Units 9-12 is reflected in the various analyses presented in the 2019 IRP.

ATTACHMENT PPPPPPPPPPPPP. Conclusion

ATTACHMENT QQQQQQQQQQQQQQQ. As set forth in the Company's 2019 IRP, Georgia Power's current supply-side plan, which incorporates the requested certification contained herein, is sufficient to provide cost-effective and reliable sources of capacity and energy for customers. The request contained in this 2019 Certification Application is in the public interest and substantially complies with the relevant Commission rules. Therefore, the Company requests that the Commission approve this Certificate Amendment.

ATTACHMENT RRRRRRRRRRRRRR.



**ATTACHMENT SSSSSSSSSSSSS. APPLICATION FOR
DECERTIFICATION OF PLANT HAMMOND UNITS 1-4, PLANT MCINTOSH
UNIT 1, PLANT ESTATOAH UNIT 1, PLANT LANGDALE UNITS 5-6, AND
PLANT RIVERVIEW UNITS 1-2**

ATTACHMENT TTTTTTTTTTTTTT. Introduction

ATTACHMENT UUUUUUUUUUUUUUUU. Together with the 2019 IRP, the Company hereby files this Application for Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 (“2019 Decertification Application”) pursuant to O.C.G.A. § 46-3A-3 and Commission Rule 515-3-4-08. The units presented for decertification represent 983 megawatts (“MW”) of generating capacity. The Company hereby incorporates by reference all other portions of the Company’s 2019 IRP filing into this 2019 Decertification Application.

ATTACHMENT VVVVVVVVVVVVVV. Decertification Requests

ATTACHMENT WWWWWWWWWWWWWWWWW. Need for Decertification

ATTACHMENT XXXXXXXXXXXXXXXXX. As described in CHAPTER 1., CHAPTER 9., and CHAPTER 10. of the IRP Main Document, retirement and decertification is the most cost-effective approach for Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2. While these units have provided benefits to customers over the years, the analysis provided in the Unit Retirement Study in Technical Appendix Volume 2 demonstrates that retirement of these units at this time is in the best interest of all customers.

ATTACHMENT YYYYYYYYYYYYYYYY. Plant Hammond Units 1-3 are coal-fired units that were placed in service at various times between 1954 and 1955, each with a generating capacity of 110 MW. Plant Hammond Unit 4, with a generating capacity of 510 MW, was placed in service in 1970. Plant McIntosh Unit 1 has a capacity of 142.5 MW and was placed in service in 1979. Plant Estatoah Unit 1 is a 100-kW hydro generating unit built in 1929 and acquired by Georgia Power in 1960. Plant Langdale Units 5-6 are hydro generating units built in 1908, with a combined capacity of 200 kW. Plant Riverview Units 1-2, also hydro generating facilities, have a combined capacity of 100 kW and were built in



1918. The Plant Langdale and Plant Riverview units were acquired by the Company in 1930. The economic analyses for Plant Hammond Units 1-4 and Plant McIntosh Unit 1 are contained in the Unit Retirement Study in Technical Appendix Volume 2. The analysis for each plant shows that continued operations is not in the best interest of customers. Similarly, the Unit Retirement Study contains the economic analyses for Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2, respectively, which shows that decertification of these units is in the best interest of customers.

ATTACHMENT ZZZZZZZZZZZZZZZ. Analysis of Transmission Impacts

ATTACHMENT AAAAAAAA. In accordance with the Commission's order in Docket No. 31081, the Company performed an analysis of the results of the requested decertifications on transmission facilities. There are no transmission facilities added, modified, or avoided as a result of this decertification request.

ATTACHMENT BBBB. Cost Recovery

ATTACHMENT CCCCCCCCCCCCCCCC. In connection with the proposed decertifications, the Company requests that the Commission approve the following:

1. Reclassification of the remaining net book value of Plant Hammond Units 1-4 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a period equal to the respective units' remaining useful lives approved in Docket No. 36989;
2. Reclassification of the remaining net book value of Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 as of their respective retirement dates to regulatory asset accounts and the amortization of such regulatory asset accounts ratably over a 3-year period in the next base rate case; and
3. Reclassification of any unusable material and supplies inventory balance remaining at the unit retirement dates to a regulatory asset for recovery over a period to be determined by the Commission in the Company's next base rate case, consistent with treatment of such balance in the 2016 IRP Order.



ATTACHMENT DDDDDDDDDDDDDDDDD. Conclusion

ATTACHMENT EEEEEEEEEEEEEEE. As set forth in the Company's 2019 IRP, Georgia Power's current supply-side plan, which incorporates the requested decertifications contained herein, is sufficient to provide cost-effective and reliable sources of capacity and energy for customers. The known and reasonably expected effects of these retirements on the Company's 2019 IRP are described more fully in the IRP Main Document and the Technical Appendices. The requests contained in this 2019 Decertification Application are in the public interest and substantially comply with the relevant Commission rules. Therefore, the Company requests that the Commission approve the following:

1. Decertification of Plant Hammond Units 1-4, Plant McIntosh Unit 1, Plant Estatoah Unit 1, Plant Langdale Units 5-6, and Plant Riverview Units 1-2 effective as of the date of the final order in this proceeding; and
2. The related cost recovery as detailed in the Cost Recovery section of this 2019 Decertification Application.



**ATTACHMENT FFFFFFFFFFFFFF. STEWART COUNTY STATUS
REPORT**

ATTACHMENT GGGGGGGGGGGGGGGGG. Executive Summary

ATTACHMENT HHHHHHHHHHHHHHHHH. On March 1, 2017, Georgia Power notified the Commission of its intention to suspend work on the Stewart County Site Investigation (“Suspension Filing”). The Site Investigation explored the option of pursuing new nuclear generation as a potential future baseload option at a site in Stewart County, Georgia.

ATTACHMENT I|||||||||. As the Company explained in the Suspension Filing, the site suitability work had been completed, and the Company would soon begin the necessary activities to close out and preserve the work that was performed during the Stewart County Site Investigation. The suspension of investigation activities acknowledged changing factors that altered the timing for the deployment of new nuclear. The suspension provides the Commission and the Company the ability to further evaluate the timing for deployment of new nuclear using updated assumptions in a comprehensive triennial Integrated Resource Plan proceeding.

ATTACHMENT JJJJJJJJJJJJJJJJJ. On March 7, 2017, the Commission approved the Company’s Suspension Filing. In accordance with the approved Order, “the Company shall not recommence the Stewart County Site Investigation or incur additional related costs beyond the cost necessary to close out and preserve the work performed to date without prior Commission approval.”

ATTACHMENT KKKKKKKKKKKKKKKKK. As of June 20, 2018, the Company has completed all planned site activities.

ATTACHMENT LLLLLLLLLLLLLL. As stated in the 2017 Annual Status Report, activities were taking place to ensure that the site would be available for future use should the need for additional generating capacity arise. Following the 2018 Annual Status Report, the meteorological tower was dismantled and stored on-site. No further preservation activities are planned, thereby concluding all work associated with the Stewart County Site Investigation. The site remains in a “preserved” state pursuant to the Commission’s Order.



ATTACHMENT MMMMMMMMM. As of December 31, 2018, the Company has incurred approximately \$49 million in actual expenditures during the Stewart County Site Investigation. All accounts used for the Stewart County Site Investigation have been closed.

ATTACHMENT NNNNNNNNNNNNNNN.

ATTACHMENT OOOOOOOOOOOOOOO. Authorized Cost Update

ATTACHMENT PPPPPPPPPPPPPP. Site Investigation and COL application related cost activities are as follows:

ATTACHMENT QQQQQQQQQQQQQQQQQ. Labor – These costs reflect labor from multiple departments, including leased employees, to support the Site Investigation activities (e.g. administrative support, accounting, project planning, engineering, COL application development, etc.). Management oversight of the Stewart County Site Investigation activities is also included.

ATTACHMENT RRRRRRRRRRRRRRR. Overhead – These costs are a percentage of the normal labor costs.

ATTACHMENT SSSSSSSSSSSSSSS. Meals & Travel – Travel and expenses associated with the Site Investigation.

ATTACHMENT TTTTTTTTTTTTTTT. Relocation – Costs associated with relocating Company employees supporting the Site Investigation.

ATTACHMENT UUUUUUUUUUUUUUUU. Contract Labor – Costs associated with services from outside vendors to support specific scopes of work within the Site Investigation. Note that contractors may also use subcontractors to support their activities. For example, a key subcontractor for Bechtel is S&ME Inc. A list of Site Investigation major contractors, along with their primary scope of work, is provided in Table G-6 below:

ATTACHMENT VVVVVVVVVVVVVVVVV Table G-6: Site Investigation Major Contractors

Bechtel Power Company	responsible for preparing and overseeing technical work as well as developing the COL application.
Corblu	ATTACHMENT AAAAAAAATTACHMENT BBBBBBBBBBBBBB. Utilized to perform biological mapping and habitat surveys.
Lettis Consultants International, Inc.	ATTACHMENT CCCCCCATTACHMENT DDDDDDDDDDDDDDD. Primarily responsible for preparing and overseeing seismic and geological work including parts of the COL application.
New South	ATTACHMENT EEEEEEEATTACHMENT FFFFFFFFFFFFFF. Utilized to perform cultural resources surveys.
Tetra Tech	ATTACHMENT GGGGGGATTACHMENT HHHHHHHHHHHHHHH. Primarily responsible for preparing and overseeing environmental work including the environmental report needed for a COL application.

ATTACHMENT IIIIIIIIIIIII.

ATTACHMENT JJJJJJJJJJJJJJJJJ. Legal Fees – Costs associated with legal oversight and regulatory support.

ATTACHMENT KKKKKKKKKKKKKKKKK. NRC Fees – Costs associated with NRC reviews, audits, and project management support.

ATTACHMENT LLLLLLLLLLLLLL. Equipment – Costs associated with the Meteorological Tower.

ATTACHMENT MMMMMMMMMMMMMMMMM. Miscellaneous Expenses – Other less significant costs include utilities for onsite trailers, truck leases, office supplies, and dues.

ATTACHMENT NNNNNNNNNNNNNNNN. Transmission Studies – Costs associated with analysis of optimum connection locations to the power delivery system based on theoretical generation located at the site. This effort supports transmission line routing efforts and licensing/permitting activities.

ATTACHMENT OOOOOOOOOOOOOOO. Transmission Line Routing – Costs associated with analysis performed to evaluate potential transmission line routes to support licensing and permitting for the site.



ATTACHMENT PPPPPPPPPPPPPPPPP.

Stewart County Site Investigation - Cost Summary						
Southern Nuclear Operating Company						
	2014	2015	2016	2017	YTD December 2018	Total
Labor	\$279,001	\$528,553	\$1,148,624	\$359,334	\$4,877	\$2,320,389
Overhead	\$196,953	\$456,392	\$513,491	\$179,788	\$579	\$1,347,203
Meals & Travel	\$22,164	\$51,492	\$69,383	\$16,815	\$1,337	\$161,191
Relocation	\$105,888	\$13,608	\$19,036	\$21,627	\$0	\$160,159
Legal Fees	\$214,326	\$244,734	\$324,859	(\$85,811)	\$0	\$698,108
NRC Fees	\$0	\$0	\$65,053	\$15,309	\$0	\$80,362
Transmission Studies	\$24,782	\$135,582	\$23,297	\$0	\$0	\$183,661
Misc Expenses	\$2,747	\$5,738	\$18,651	\$26,018	\$0	\$53,154
Transmission Line Routing- APC	\$0	\$9,796	\$527,299	\$4,179	\$0	\$541,274
SNC Total	\$845,861	\$1,445,897	\$2,709,692	\$537,259	\$6,793	\$5,545,501
Georgia Power Company						
	2014	2015	2016	2017	YTD December 2018	Total
Labor	\$33,468	\$88,253	\$451,792	\$9,144	\$3,756	\$586,413
Overhead	\$5,944	\$7,954	\$0	\$2,287	\$0	\$16,185
Meals & Travel	\$1,532	\$7,813	\$6,790	\$3,622	\$150	\$19,907
Contract Labor	\$3,432,442	\$5,494,361	\$23,639,290	\$6,232,180	\$1,852	\$38,800,125
Legal Fees	\$10,012	\$0	\$0	\$43,811	\$0	\$53,823
Equipment	\$0	\$0	\$651,166	\$0	\$25,500	\$676,666
Misc Expenses	\$483	\$9,114	\$35,697	\$6,312	\$2,350	\$53,956
Transmission Line Routing- GPC	\$80,841	\$2,529,039	\$527,987	(\$92,610)	\$0	\$3,045,257
Georgia Power Total	\$3,564,722	\$8,136,534	\$25,312,722	\$6,204,746	\$33,608	\$43,252,332

ATTACHMENT QQQQQQQQQQQQQQQQQ.

Note: Values may not add due to rounding



ATTACHMENT RRRRRRRRRRRRRRRRR. RESEARCH ACTIVITIES

ATTACHMENT TTTTTTTTTTTTTTTTT. Generation Fleet: Modernization

ATTACHMENT UUUUUUUUUUUUUUUUUU. SCS R&D is focused on improving all components of the existing fossil fleet, with primary work in areas that include natural gas turbines, cooling systems, advanced materials and instruments and controls. This program works to maximize fleet flexibility, availability and performance; analyze, develop and demonstrate advanced generation concepts for retrofit or greenfield applications; and provide generation technology assessment for system planning. Example projects include:

ATTACHMENT VVVVVVVVVVVVVVV. Electric Power Research Institute (“EPRI”)
Insight through Integration of Information for Intelligent Generation (“I4GEN”) – This initiative takes a holistic approach to create a digitally connected and dynamically optimized power plant. The I4GEN concept enhances an operating workforce through use of a digital platform that produces real-time information to estimate equipment condition, enhance maintenance, optimize operations and augment decision-making abilities.

ATTACHMENT WWWWWWWWWWWWWWWWW. *Combined-Cycle Inlet Filtration Evaluations* – Lab testing of both used filters and new filter designs are being evaluated to



support the fleetwide bid process for new inlet filters across the natural gas combined-cycle fleet. Results of the R&D will ensure optimal cost and performance of the new filters.

ATTACHMENT XXXXXXXXXXXXXXXXX. *Advanced Control: Concepts, Design and Tuning* – Emerging technologies with the potential to enhance process control in the utility industry are being investigated, developed and demonstrated. EPRI's Combustion Dynamics Monitoring System is being used at Southern Company subsidiary Southern Power's Monitoring and Diagnostic Center and has already identified asset damages requiring attention.

ATTACHMENT YYYYYYYYYYYYYYYYYY. Generation Fleet: Carbon Capture

ATTACHMENT ZZZZZZZZZZZZZZZZZ. This program supports the development of economic CO₂ capture technology, demonstrates secure CO₂ storage within the Southern Company territory, engages in stakeholder outreach to ensure support for technology deployment and promotes the development of new systems, tools, modeling capabilities and business models to support commercial deployment.

ATTACHMENT AAAAAAAAAAAAAAAA. *National Carbon Capture Center* – Located in Wilsonville, Alabama, the DOE-sponsored National Carbon Capture Center is a world-class neutral research facility working to advance technologies to reduce greenhouse gas emissions from natural gas- and coal-based power plants. The center works with third-party developers to bridge the gap between laboratory research and large-scale demonstrations and provides realistic testing conditions plus the infrastructure to explore the most promising, cost-effective CO₂ capture technologies.

ATTACHMENT BBBB BBBB BBBB BBBB. *Carbon Storage Assurance Facility Enterprise (“CarbonSAFE”)* – This Southern States Energy Board project is drilling test wells and gathering subsurface data to assess the feasibility of CO₂ storage in geologic formations in Kemper County, Mississippi. This data will be used to develop conceptual models for commercial-scale CO₂ injection operations for the site or as a regional CO₂ storage hub.



ATTACHMENT CCCCCCCCCCCCCCCC. Generation Fleet: Environmental Controls and Sustainability

ATTACHMENT DDDDDDDDDDDDDDDDDDD. SCS R&D is exploring new technologies to minimize compliance costs for current and future power plant emissions limitations. Activities focus on wastewater, solid waste, advanced particulate, sulfur oxide ("SO_x"), NO_x, CO₂, mercury and air toxics management technologies. SCS R&D is also working on developing technologies that ensure water and fuel resources are utilized as efficiently as possible. Another focus of research involves developing technologies that provide new markets for products and byproducts, such as ash and gypsum. Example projects include:

ATTACHMENT EEEEEEEEEEEEEEEE. Water Research and Conservation Centers – Building on successful testing at the Water Research Center at Georgia Power's Plant Bowen, Southern Company is expanding the focus of this research with the Water Research and Conservation Center ("WRCC") located at Plant Bowen and Plant McDonough-Atkinson. This expansion will provide Southern Company and Georgia Power with the infrastructure to identify the most promising water technologies to better manage and conserve water across the Company's thermoelectric power generation sites – as well as achieve short- and long-term water management goals.

ATTACHMENT FFFFFFFFFFFFFF. The WRCC at Plant Bowen will maintain its focus on complying with environmental regulations, while continuing the testing and evaluation of pilot systems that are nearing commercialization. Since 2012, more than 50 technologies have been tested at Plant Bowen within seven key research areas. Of those tested, several successful technologies are being implemented across the energy industry and other industrial applications.

ATTACHMENT GGGGGGGGGGGGGGGGGGG. The WRCC at Plant McDonough will promote advancements in power plant cooling systems leading to reduced freshwater withdrawal and consumption, as well as improved plant efficiency while optimizing total cost and energy generation. Work at Plant McDonough will provide the necessary resources and opportunities required to close the industry's research gaps in cooling and heat transfer improvements.



ATTACHMENT HHHHHHHHHHHHHHHHHHH. Wastewater**Treatment**

Demonstrations – Several technologies have been demonstrated across the Southern Company fleet to support compliance with EPA's ELG rule – including demonstration of a 25 gallons-per-minute biological treatment technology from Frontier Water Systems. Work has led to modifications of Frontier's technology and has increased Southern Company's understanding of operations and maintenance and staffing requirements.

ATTACHMENT IIIIIIIIIIIII. Byproduct Utilization – Beneficial use studies are focused on three areas: higher-value markets for existing saleable materials, new markets for off-spec materials (including ponded ash) and support for existing markets. Research into higher-value markets includes a collaboration with the University of North Dakota Energy and Environment Research Center investigating extraction of rare earth elements from Powder River Basin ash. Research to support existing markets includes a collaboration with the US Department of Agriculture and Duke Energy on agricultural uses of gypsum. Ongoing research at Georgia Institute of Technology ("Georgia Tech") includes support for beneficial use of ash in concrete, as well as novel uses for ponded and biomass ashes.

ATTACHMENT JJJJJJJJJJJJJJJJJ. Evaluation of Next-Generation Monitoring Systems – Advanced monitoring systems for hydrogen chloride ("HCl"), sulfur trioxide ("SO₃") and NH₃ are needed to increase the effectiveness of sorbent injection systems and further lower O&M costs at coal and gas plants. Southern Company evaluated cross-duct tunable diode lasers for HCl and NH₃ at Alabama Power's Plant Barry coal unit and Georgia Power's Plant McIntosh combined-cycle unit, respectively. The technologies are showing promise for continuous monitoring of these constituents in the flue gas.

ATTACHMENT KKKKKKKKKKKKKKKKK. Advanced Energy Systems

ATTACHMENT LLLLLLLLLLLLLL. Molten Chloride Fast Reactor – Efforts to advance Generation-IV nuclear include a collaborative between Southern Company, TerraPower, EPRI, Oak Ridge National Laboratory, Idaho National Laboratory and Vanderbilt University to support design and construction of an Integrated Effects Test for the molten chloride fast reactor ("MCFR"). The MCFR has the potential to produce high-quality, sustainable energy at low cost with inherent safety and reliability, a low waste profile, polygeneration benefits and enhanced security.



ATTACHMENT MMMMMMMMMMMMMMMMM. *Hydrogen Economy* – Southern Company is engaging domestically and internationally through hydrogen R&D projects and collaboration with the International Energy Agency Hydrogen Implementing Agreement, EPRI (Technology Innovation and Energy Storage Programs), the US Department of Energy and its national laboratories, technology developers, industrial gas companies and hydrogen users. Focus areas include hydrogen production and markets from curtailed renewables, liquid hydrogen carrier to meet system hydrogen needs and meeting hydrogen energy needs of emerging markets such as distributed generation.

ATTACHMENT NNNNNNNNNNNNNNNNN. Energy End-Use Research

ATTACHMENT OOOOOOOOOOOOOOOOO. The Energy End-Use Program works to provide customer-focused technologies and technical information to support the operating companies' efforts to sustain and grow profitable electric energy sales, promote energy efficiency and economic development and enhance customer satisfaction. Examples of Energy End-Use programs are provided below:

ATTACHMENT PPPPPPPPPPPPPPPPP. *Smart Neighborhood* – Developed by SCS R&D to demonstrate the interconnectivity of distributed resources and end-use technologies, these two projects focus on separate community sizes and microgrid configurations where resources are shared and managed to provide cost savings to the customer and new utility business models. Alabama Power's Smart Neighborhood was completed in 2018 and the two-year SCS R&D effort into the opportunities it provides is underway. Construction on the Georgia Power community has begun.

ATTACHMENT QQQQQQQQQQQQQQQQQ. *Automated Metering Infrastructure (“AMI”) Data Analytics* – Southern Company will be conducting a comprehensive data analytics pilot of 10,000 homes to identify additional value that we can derive from the large amounts of data we currently collect. The project will explore the technical feasibility of detecting major residential end-uses and whether they are operating normally with only AMI data. If successful, this will enable Southern Company to potentially offer fault detection and diagnostic services to customers and allow Southern Company to better understand and communicate with individual customers.



ATTACHMENT RRRRRRRRRRRRRRRRR. *Indoor Agriculture* – These typically all-electric facilities offer significant load growth, economic development, water conservation and food availability benefits. Demonstration facilities run by SCS R&D staff are improving throughput and cost-effectiveness to increase attractiveness to customers. SCS R&D is working with universities and other entities on optimizing the wavelength of grow lights, evaluating the environmental impacts and improving product transportation.

ATTACHMENT SSSSSSSSSSSSSSS. *Electrotechnologies for Industrial Waste Treatment* – US industries are faced with new challenges as the costs and liabilities associated with waste management continue to escalate due to evolving regulations. This research area is identifying and investigating promising electrotechnologies for solid waste management, air control applications and water treatment.

ATTACHMENT TTTTTTTTTTTTTTT. *Heavy-Duty Electric Vehicle (“EV”) Charging Hardware Development* – EV manufacturers are working toward the development of vehicle chargers capable of 4.5 MW power levels to support the electrification of semi-trucks, buses and other heavy-duty vehicles. Currently available charging technology typically operates at power levels of 500 kW and below. This project seeks to advance the design, standardization and testing of new hardware approaches to charging at higher (target of 4.5 MW) power levels.

ATTACHMENT UUUUUUUUUUUUUUUU. *EV Charging Network Interoperability* – This project will develop and demonstrate interoperability between various charging networks and vehicle manufacturers. The goal is to improve the EV charging customer experience by allowing the use of one account across the various networks. This will reduce confusion of where charging stations are available and drive adoption of electric vehicles. This project will conclude with a demonstration of at least three automotive OEMs and two network operators participating in successful charging events.

ATTACHMENT VVVVVVVVVVVVVVV. *Smart Cities* – Increased urbanization has driven communities to seek new solutions to improve safety, sustainability and reliability for energy, transportation, water and other utility services. Improvements in information and communication technologies and the smart and connected use of these technologies offer a pathway for cities to develop systems that deliver these solutions. As these trends continue and smart cities initiatives develop, electric utilities are becoming “digital utilities,” uniquely



positioned to support smart city goals with their communication networks and vertical infrastructure acting as the foundation. This project evaluates and tests smart city technologies that create opportunities to leverage existing assets allowing development of new business opportunities.

ATTACHMENT WWWWWWWWWWWWWWWWWWWWW. Industrial Energy Efficiency Program – This program brings new industrial electrotechnologies or new applications of existing technologies to the market. One example would be additive manufacturing (3-D printing) to enhance manufacturing within the service territory.

ATTACHMENT XXXXXXXXXXXXXXXXXXXX. Building Energy Efficiency Program – The purpose of this program is to identify, assess and demonstrate new energy-efficient technologies and software products for application in building design, energy-related HVAC, water heating, lighting, appliances and building structures.

ATTACHMENT YYYYYYYYYYYYYYYYYYYY. Power Quality (PQ) Program – The PQ program identifies, assesses and demonstrates new PQ technologies that will increase customer productivity by providing for point-of-use enhanced PQ and assist personnel with troubleshooting and analysis. This program evaluates other end-use technologies and their PQ impacts to the power delivery system. The PQ Analysis Tools are used for troubleshooting harmonics, characterizing voltage sag waveforms, automatic distribution capacitor analysis and geomagnetically induced currents.

ATTACHMENT ZZZZZZZZZZZZZZZZZ. Power Delivery

ATTACHMENT AAAAAAAAAAAAAAA. The Power Delivery, or T&D, Program works to develop and deploy the next generation of T&D technologies to improve reliability and resiliency, reduce cost and modernize the grid. Following are some examples of these efforts:

ATTACHMENT BBBB BBBB BBBB BBBB BBBB. Smart Sensor Suite – In collaboration with EPRI, SCS R&D is completing two major sensor installations that will advance visualization and increase the ability to perform condition-based maintenance (“CBM”) across the transmission system.



- Over 20 sensors were installed at the Magella Transmission Substation. The Magella host site will demonstrate opportunities to increase asset condition awareness on transmission assets, improve the ability to perform CBM, provide greater visualization for grid modernization efforts and reduce O&M.
- Geomagnetically induced current (“GIC”) sensors were installed on a transformer at the Clay Transmission Substation. By understanding GIC impact on transformers, Southern Company can develop proper transmission planning models to predict impacts of geomagnetic disturbances (“GMD”) over the entire transmission system and comply with NERC regulations. The Clay sensor installation is part of a larger-scale project to gain an industry-wide understanding of GMD effects on the transmission system.

ATTACHMENT CCCCCCCCCCCCCCCCCCCC. *Digital Substation* – This project uses fiber-optic communication with International Electrotechnical Commission (“IEC”) 61850 protocol and/or Schweitzer time domain protocol throughout the substation. The benefits include lower-cost installation and maintenance and increased ability for protection system automation.

ATTACHMENT DDDDDDDDDDDDDDDDDDDDDDDDD. *Edge-of-Network Grid Optimization (“ENG0”)* – These pole-mounted distributed capacitance devices improve voltage control as more distributed energy resources come online, allowing for the continued advancement toward automatic grid configurations. Field demonstrations of 700 devices are underway across the System.

ATTACHMENT EEEEEEEEEEEEEEEE. *High-Temperature Conductor Connectors* – High-temperature, low-sag conductors are being used more commonly across Southern Company to increase capacity and improve performance of transmission lines. SCS R&D work is addressing uncertainties about the impact of high temperatures on connected switches and other components.

ATTACHMENT FFFFFFFFFFFFFF. *Unmanned aerial systems (drones)* – SCS R&D is working with EPRI to develop beyond-visual-line-of-sight capabilities and automation capabilities to perform fully automated, autonomous transmission infrastructure inspections. Artificial intelligence is also being incorporated to identify anomalies on the transmission system.



ATTACHMENT GGGGGGGGGGGGGGGGGGGGGGGGG. *DER Integration and Microgrids* –

Multiple demonstrations and evaluations of microgrids, their controllers and distributed energy resources are underway. With these technologies, an overarching DERMS is being developed for control of these systems.

ATTACHMENT HHHHHHHHHHHHHHHHHHHHHHHHHHH. *Grid Visualization and Analytics*

Center – Completed in late 2018, this center will improve both distribution and transmission operators' situational awareness. The intent is to provide analytics and visualization software vendors/developers' access to near-real-time grid data to test and harden their technologies.

ATTACHMENT IIIIIIIIIIIII. *Synchrophasor Program and Tools* – Synchrophasors

provide high-resolution, time-synchronized electrical measurements (with magnitude and phase angle) simultaneously from across the grid, providing optimization and problem prediction benefits. This project now has 65 devices dispersed across the System.

ATTACHMENT JJJJJJJJJJJJJJJJJJJJJJJJJJJ.**ATTACHMENT KKKKKKKKKKKKKKKKKKKKKKKKK.** *Transformer of the Future* – This

multiyear project focuses on new transformer technologies. Lab testing is being conducted on new chemical markers, online dissolved gas analysis and bushing monitor technologies.

ATTACHMENT LLLLLLLLLLLLLLLLLL. *Transmission Monitoring, Diagnostics*

and Visualization – A pilot demonstration of the Transmission Monitoring, Diagnostics, and Visualization ("TMDV") effort is complete. Significant progress was made in fault location, line switch operation verification and relay data extraction to facilitate analytics. Learnings from this multi-year project include: 1) a novel automated fault location method that takes humans out of the loop from event detection to the display of the fault in relation to transmission structures on a map. This will not only improve work efficiency but also facilitate faster customer restoration; 2) a line switch operation verification tool that has proved valuable beyond its original intent by alerting Operations personnel to other unrelated undiagnosed issues; 3) automated extraction of relay files to a database to permit data analytics including the calculation of cumulative arc energy and other metrics used for asset health assessment

ATTACHMENT MMMMMMMMMMMMMMMMMMM. *Cyber-Physical Modeling and*

Simulation for Situational Awareness ("CYMSA") – In partnership with Georgia Tech and



DOE, Southern Company is developing and demonstrating technology and/or techniques to detect and respond to adversarial cyber activity that could impact the grid.

ATTACHMENT NNNNNNNNNNNNNNNNNNN. Renewables, Storage, and Distributed Generation (“RSDG”)

ATTACHMENT OOOOOOOOOOOOOOOOOOO. Southern Company’s RSDG R&D represents a collaborative effort between the Generation and Retail Marketing business units to develop technologies associated with renewable resources (e.g., wind, solar, biomass), energy storage and distributed generation. Objectives include providing technical, economic, and operational research to evaluate, develop and demonstrate future technology options for the company and its customers. Examples of RSDG efforts include:

ATTACHMENT PPPPPPPPPPPPPPPPPPP. *Southeastern Solar Research Center (“SSRC”)* – The SSRC studies how the Southeastern US climate affects the performance of solar PV systems. Research is particularly focused on the development and application of accelerated aging methods, which will help predict PV panel performance and degradation over time and provide insight into optimal design of PV systems for electric utilities. Located in Birmingham, Alabama, the SSRC also serves as a host site for evaluating advanced inverter technologies. An advanced weather station complements research on short term solar forecasting and energy storage.

ATTACHMENT QQQQQQQQQQQQQQQQQQQ. *University of Georgia (“UGA”) 1-MW Solar Demonstration Project* – This 1-MW PV Georgia Power demonstration located at UGA monitors O&M for various tracking systems to gain a better understanding of plant performance. The plant provides insight into performance at different solar orientations and advanced technologies to increase PV plant output. This demonstration project also supports research activities related to advanced solar plant design and smart inverter testing as described below:

ATTACHMENT RRRRRRRRRRRRRRRRRRR. *Advanced Solar Plant Design* – Projects are exploring new solar plant designs and configurations with a focus on cost reduction, increased energy output, and easier integration with storage and the grid.

ATTACHMENT SSSSSSSSSSSSSSSSS. *Smart Inverter Testing and Application* – The demonstration site is also used to evaluate smart inverter capability. The project will test



a variety of voltage and power regulation modes to determine the effectiveness of smart inverters at managing grid impacts of a solar resource.

ATTACHMENT TTTTTTTTTTTTTTTTT. PV Inspections – These projects include development and evaluation of innovative inspection techniques for solar facilities, including infrared (“IR”), electroluminescence (“EL”), ultraviolet (“UV”) and UV-Fluorescence (“UV-F”) imaging. These technologies can detect existing failures and potential failure points in solar panels and plants. Some techniques are being implemented with manned aircraft and drones. Work is also being done to evaluate the effectiveness of algorithms for detecting failures and underperformance in solar plants.

ATTACHMENT UUUUUUUUUUUUUUUUU. Solar Forecasting – Southern Company, along with several utilities and vendors, is part of a team lead by EPRI that was awarded DOE funding for a solar forecasting project: Operational Probabilistic Tools for Solar Uncertainty (“OPTSUN”). OPTSUN seeks to integrate improved probabilistic solar forecasts into tools used in fleet operations. This builds upon previous work with EPRI to evaluate the accuracy of solar forecasting vendors.

ATTACHMENT VVVVVVVVVVVVVVVVV. Rooftop Solar Adoption Forecasting – SCS R&D is participating in a multi-utility EPRI project that is building survey-based models to forecast residential rooftop solar adoption and better understand customer preferences related to solar. Forecasts are built around census data to provide zip code-level estimates, and can be filtered based on customer-owned, leased and community solar models.

ATTACHMENT WWWWWWWWWWWWWWWWWWW. Wind Evaluations – Projects are underway to assess wind resources within the Southeast. SCS R&D is partnering with Georgia Power to complete a wind feasibility study to better assess wind resources in the state of Georgia. This project involves the installation of four LiDAR units and one sonic detection and ranging (“SODAR”) unit. The project will provide actual measured wind resource data up to 200 meters above the ground. SODAR wind resource data has also been collected at Chandler Mountain, Alabama, for a pre-feasibility wind development assessment. This work will provide estimated potential annual energy production and high-level costs for wind facility based on these sites.

ATTACHMENT XXXXXXXXXXXXXXXXXXXX. Residential Battery Test Stand – SCS R&D is also evaluating behind-the-meter residential storage systems that can provide



renewable integration, demand management and back-up power. Located at Southern Company's R&D Laboratory in Irondale, Alabama, the residential battery test stand enables researchers to "plug and play" residential energy storage systems, run simulations for various use cases and perform side-by-side evaluation of technologies. The project includes the ability to simulate a residential home containing solar PV and energy storage systems with typical home appliances. Multiple residential battery systems are being tested in support of the Georgia Power Smart Neighborhood project.

ATTACHMENT YYYYYYYYYYYYYYYYYYYYY. *Energy Storage Performance and Reliability Data Analysis* – This project will develop a data repository and analysis platform to collect and analyze data from energy storage systems and answer key questions about performance, reliability and degradation over time. This effort will leverage infrastructure and lessons learned from EPRI's ongoing work establishing databases for understanding component reliability and failure modes of utility assets such as transformers and PV systems.

ATTACHMENT ZZZZZZZZZZZZZZZZZZZ. *Small-Scale Battery Storage Demonstration with Solar PV* – Two 5 kW/20 kWh energy storage systems have been installed to demonstrate solar PV integration. The systems are located in Gulfport, Mississippi, and Mobile, Alabama. These projects will provide experience using small-scale battery storage for PV smoothing and shifting on small scale systems.

ATTACHMENT AAAAAAAAAAAAAAA. *Commercial-Scale Battery Storage Demonstrations* – Two 40kW/50kWh energy storage systems have been installed in Gulfport, Mississippi, and Alpharetta, Georgia, to further understand operational challenges, integration and the value of storage. The systems are connected at the edge of the grid, between the secondary of the transformer and the customer.

ATTACHMENT BBBB BBBB BBBB BBBB BBBB. Another commercial-scale project, a 250-kW/1 MWh Tesla Powerpack lithium-ion system, previously interconnected at a Gulf Power facility in Pensacola, Florida, will be installed at a location in Alabama. The project will enable a better understanding of the siting, installation and operational requirements of commercial- and industrial-scale energy storage systems, as well as the value storage applications can offer customers and the energy provider through peak shaving, demand management, ancillary services, energy arbitrage and backup power. This project is also



providing information for the EPRI energy storage performance and reliability data analysis effort.

ATTACHMENT CCCCCCCCCCCCCCCCCCCCC. *Cedartown Utility-Scale Battery Storage with Solar PV* – This lithium-ion energy storage project is evaluating the operation and benefits of a 1-MW/2-MWh system integrated with a 2-MW solar facility in Cedartown, Georgia. SCS R&D is demonstrating renewable integration, peak shaving and voltage support to help establish a technical and economic foundation for future grid deployments. This project is also providing information for the EPRI energy storage performance and reliability data analysis effort.

ATTACHMENT DDDDDDDDDDDDDDDDDDDDDDDDD. *Energy Storage Research Center (“ESRC”)* – This collaborative effort between Southern Company, Southern Research Institute, EPRI, DOE’s Office of Electricity and Oak Ridge National Laboratory serves as an industry-wide resource for testing multiple energy storage technologies under actual grid conditions. Located in Birmingham, Alabama, the center will help facilitate the advancement of hardware and software components of energy storage systems and help develop and validate standards for the integration and operation of storage technologies. Ultimately the ESRC will be part of a decentralized energy storage collaboration network comprised of EPRI, utilities and DOE to inform the safe and effective deployment of advanced energy storage technology.

ATTACHMENT EEEEEEEEEEEEEEEEEEE. *Comparison and Optimization of Design Options for Compressed Air Energy Storage (CAES)* – The purpose of this project is to evaluate different CAES design. CAES is one of the lowest-cost and most mature technologies for energy storage and is one of few technologies that can provide bulk energy storage for long durations.

ATTACHMENT FFFFFFFFFFFFFF. *Landfill Gas Demonstration of Bloom Energy Fuel Cell Technology Pilot* – Southern Company and Bloom Energy are partnering to demonstrate a solid-oxide fuel cell operation on landfill gas. The pilot will allow Bloom Energy and Southern Company to understand the feasibility of solid-oxide fuel cells as a new, clean solution for utilizing landfill gas. The project is expected to pave the way for commercial deployment of large-scale landfill gas-based fuel cell systems.



ATTACHMENT GGGGGGGGGGGGGGGGGGGGGGGGG. *Gencell Alkaline 5-kW Fuel Cell*

Demonstration – SCS R&D is expanding its evaluation of fuel cell technologies with a demonstration of the Gencell alkaline fuel cell at the Irondale R&D Laboratory. The project will evaluate the performance, O&M needs and costs for deploying this type of technology in Uninterruptible Power Supply (“UPS”) applications. Relevant uses for Southern Company include UPS for substation auxiliary power and backup power for telecommunication towers.

ATTACHMENT HHHHHHHHHHHHHHHHHHHHHHHHH. *Microgrid at Georgia Tech’s Tech*

Square (High-Performance Computing Center) – Georgia Power and Southern Company are partnering with Georgia Tech to develop a microgrid test bed. This project will demonstrate the integration and control of multiple distributed energy resources within a microgrid. DER assets will be located on-site at Georgia Tech and feature solid-oxide fuel cell, battery energy storage system, and natural gas and diesel fueled generators. This project will help the company understand utility and customer benefits of microgrids and serve as a research platform to demonstrate new distributed energy technologies.



ATTACHMENT III. ACRONYMS, ABBREVIATIONS, AND TERMINOLOGY



ATTACHMENT XXXXXXXX	ATTACHMENT XXXXXXXX . Defined in the Glossary of Terms Used in NERC Reliability Standards - https://www.nerc.com/files/glossary_of_terms.pdf
ATTACHMENT ZZZZZZZZ	ATTACHMENT ZZZZZZZZ . Budget
Budget 2019	2019 Load and Energy Forecasts
ATTACHMENT BBBB	ATTACHMENT BBBB . Boiling
BWR	Water Reactor
ATTACHMENT DDDDDD	ATTACHMENT DDDDDD . Commercial
C&I	and Industrial
ATTACHMENT FFFFFFFF	ATTACHMENT FFFFFFFF . Compressed Air Energy Storage
CAES	
ATTACHMENT HHHHHHHHHHHHHHHHHHH	ATTACHMENT HHHHHHHHHHHHHHHHHHH . Condition-based maintenance
CBM	
ATTACHMENT JJJJJJJJJ	ATTACHMENT JJJJJJJJJ . Combine
CC	d Cycle
ATTACHMENT LLLLLLLL	ATTACHMENT LLLLLLLL . Carbon
CCC	Capture and Compression
ATTACHMENT NNNNNNNN	ATTACHMENT NNNNNNNN . Coal
CCR	Combustion Residuals
ATTACHMENT PPPPPP	ATTACHMENT PPPPPP . Cooling
CDH	Degree Hours
ATTACHMENT RRRRRRRR	ATTACHMENT RRRRRRRR . Cubic Feet
CFS	Per Second
ATTACHMENT TTTTTTTT	ATTACHMENT TTTTTTTT . Cascade
CHAT	d Humidified Advanced Turbine
ATTACHMENT VVVVVVVV	ATTACHMENT VVVVVVVV . Carbon
CO₂	Dioxide
ATTACHMENT XXXXXXXX	ATTACHMENT XXXXXXXX . Commercial
COD	Operation Date
ATTACHMENT ZZZZZZZZ	ATTACHMENT ZZZZZZZZ . Combined
COL	License
ATTACHMENT BBBB	ATTACHMENT BBBB . Georgia
Commission	a Public Service Commission
ATTACHMENT DDDDDD	ATTACHMENT DDDDDD . Georgia
Company	Power Company
ATTACHMENT FFFFFFFF	ATTACHMENT FFFFFFFF . Charles
CRA	River Associates
ATTACHMENT HHHHHHHHHHHHHHHHHHH	ATTACHMENT HHHHHHHHHHHHHHHHHHH . Capital Recovery Factor
CRF	
ATTACHMENT JJJJJJJJJ	ATTACHMENT JJJJJJJJJ . Custom
CRSP	er Renewable Supply Procurement
ATTACHMENT LLLLLLLL	ATTACHMENT LLLLLLLL . Cost
CSE	of Saved Energy
ATTACHMENT NNNNNNNN	ATTACHMENT NNNNNNNN . Com
CT	bustion Turbine
ATTACHMENT PPPPPP	ATTACHMENT PPPPPP . Cyber-Physical Modeling and Simulation for Situational Awareness
CYMSA	
ATTACHMENT RRRRRRRR	ATTACHMENT RRRRRRRR . Distribute
DER	d Energy Resource



ATTACHMENT TTTT	ATTACHMENT UUUUUUUUUUUUUUUUUUUUUU. Distributed Energy Resource Management System
ATTACHMENT VVVV	Distributed Generation
ATTACHMENT XXXXXX	Department of Energy
ATTACHMENT ZZZZZZ	Demand Plus Energy Credit
ATTACHMENT BBBB	Unmanned aerial systems
Drones	
ATTACHMENT DDDDDD	Demand-Side Management
DSM	
ATTACHMENT FFFFFFFF	Demand-Side Management Working Group
DSMWG	
ATTACHMENT HHHHHHHH	DSM Planning Process
DSM Program	
Planning Approach	originating from the 2010 IRP
ATTACHMENT JJJJJJJJ	Demand-Side option
DSO	
ATTACHMENT LLLLLL	Environmental Compliance Cost Recovery
ECCR	
ATTACHMENT NNNNNNNN	Environmental Compliance Strategy
ECS	
ATTACHMENT PPPPPP	Electroluminescence
EL	
ATTACHMENT RRRRRR	Effluent Limitations Guidelines
ELG	
ATTACHMENT TTTT	See model description in ATTACHMENT A.
EnerSim	
ATTACHMENT VVVV	Edge-of-Network Grid Optimization
ENGO	
ATTACHMENT XXXXXX	Environmental Protection Agency
EPA	
ATTACHMENT ZZZZZZ	Environmental Protection Division
EPD	
ATTACHMENT BBBB	European Pressurized Water Reactor
EPR	
ATTACHMENT DDDDDD	Electric Power Research Institute
EPRI	
ATTACHMENT FFFFFFFF	Economic Simplified Boiling Water Reactor
ESBWR	
ATTACHMENT HHHHHHHH	Energy Storage Research Center
ESRC	
ATTACHMENT JJJJJJJJ	Expected Unserved Energy
EUE	
ATTACHMENT LLLLLL	Electric Vehicle
EV	
ATTACHMENT NNNNNNNN	Fuel Cell Combined Cycle
FCCC	









ATTACHMENT LLLLLLLLLLLLLLLLLLLLLLLLLLLLLLLLL.

